Submitted By: Mahindra Susten Pvt Ltd					Date: 15th June 2026
Comments and Suggestions on Staff Paper on Capacity Market for Electricity in India					
S. No.	**Theme / Section**	**Existing Clause**	**Proposed Modifications**	**Rationale/Remarks/ Comments**	**Specific drafting suggestion**
1	General / Overall design	The Staff Paper proposes capacity market alternatives for RA, reserve capacity and secondary short-term capacity trading.	Support the intent of improving resource adequacy, but recommend a phased and evidence-led implementation rather than immediate full-scale migration of long-term procurement to market-indexed capacity contracts.	Capacity market design will affect discom procurement, generator bankability, market prices, consumer costs and grid reliability. A staged approach reduces implementation risk and allows calibration of capacity accreditation, settlement systems and compliance rules.	Insert an implementation roadmap: Phase 1: RA registry and capacity accreditation; Phase 2: reserve capacity pilot; Phase 3: secondary capacity market pilot; Phase 4: residual/backstop RA market; Phase 5: full RA capacity auctions after regulatory impact assessment.
2	General / RA obligation scope (Para 25-26)	RA responsibility is placed primarily on States/Discoms.	Clarify that RA obligations and cost responsibility should apply to all load-serving entities and load migration categories, including discoms, open-access consumers, captive/group captive users, retail suppliers where applicable, and other obligated entities.	If only discoms bear capacity cost while large consumers migrate through open access or captive arrangements, cost shifting and free-riding may arise. A common capacity obligation basis improves fairness and resource planning.	Define obligated entities, load forecast methodology, coincident peak contribution, capacity credit counting, deficiency charge and SERC/CERC coordination mechanism.
3	General / central registry (Para 25, 27, 39)	Capacity contracting, residual procurement and secondary trading are proposed, but the Staff Paper does not specify a single registry to prevent double counting.	Create a national RA/capacity registry operated by NLDC/Grid-India or another designated agency to record capacity obligations, capacity credits, transfer/novation, availability tests, penalties and settlement status.	Capacity can otherwise be pledged multiple times across long-term PPA, residual RA, reserve market and short-term capacity trades. A registry is foundational for compliance, transparency and investor confidence.	Registry should tag each MW by resource, capacity accreditation, delivery zone, contract tenor, obligation holder, counterparty, encumbrance and reserve participation status.
4	RA Capacity Market / Option 1 (Para 27)	Capacity bids are proposed solely on capacity charge, with demand curve drawn on a Net-CONE basis.	Use accredited capacity rather than installed/nameplate capacity. Capacity accreditation should be based on effective load carrying capability (ELCC) or a CEA/CERC approved capacity credit methodology, with periodic updates by technology and region.	Solar, wind, storage, hydro, gas, coal and demand response have materially different contribution to peak adequacy and stress hours. A technology-agnostic market must still be technology-aware in capacity accreditation.	CERC/CEA should publish accreditation factors for each resource class and allow project-specific accreditation where sufficient data is available.
5	RA Capacity Market / Net-CONE (Para 22-23, 27)	Staff Paper refers to Net-CONE as the basis for capacity price discovery.	Define Net-CONE through a transparent, consultative methodology, including capital cost, financing assumptions, tax, O&M, fuel and transmission costs, expected energy and ancillary revenues, degradation/augmentation costs for storage, and locational deliverability.	An opaque or single national Net-CONE can overpay some resources and underpay others, leading to inefficient entry and bankability concerns. Revenue assumptions are especially uncertain in India's evolving DAM/RTM/HP-DAM/AS markets.	Publish annual Net-CONE assumptions and sensitivities; develop separate reference Net-CONE for thermal, hydro, pumped storage, standalone BESS, RE+BESS/hybrid, gas/flexible assets and demand response where relevant.
6	RA Capacity Market / payment adequacy (Para 23)	The Staff Paper notes the question whether partial capacity charge recovery would be sufficient for investors and financial institutions.	Include explicit bankability protections: payment security, deemed availability treatment, change-in-law provisions, indexation where appropriate, dispute resolution, and clear treatment of energy-market revenue assumptions.	Capacity-only remuneration without dispatch rights may not be financeable if lenders cannot assess contracted cash flows and penalty downside. Partial recovery may not be sufficient for capital-intensive storage and new flexible capacity.	For new-build resources, allow longer contracts and minimum revenue security; for existing resources, shorter annual/seasonal capacity products may be suitable.
7	RA Capacity Market / contract tenure (Para 27; Option 3)	The Staff Paper suggests 15-year contracts under Option 1 and 10-15 years under residual RA Option 3.	Contract tenor should be linked to asset life and financing requirement: existing capacity 1-3 years; BESS 10-15 years with augmentation provisions; gas/flexible thermal 10-15 years; RE+ESS 15-25 years depending on PPA structure; hydro/PSH up to 25-40 years or a separate regulated framework.	A uniform tenor may either over-commit consumers or be insufficient for long-gestation assets such as pumped storage and hydro. Tenor differentiation improves price discovery and competition.	Include technology-specific tenor bands and allow separate auctions for new-build and existing capacity.
8	RA Capacity Market / discom demand above price cap (Para 27 Option 1 and Option 2)	The Staff Paper suggests drawing the contracting discom's demand curve slightly above the price cap to guarantee its right over contracted capacity.	Avoid or tightly limit any structural bidding above the exchange price cap. Instead, use a financial contract-for-difference (CfD), contract tagging, self-scheduling rights before market gate closure, or a settlement mechanism that does not artificially lift market MCP.	Demand bids above the cap can distort DAM/RTM price formation, affect non-contracting consumers, and create regulatory credibility risk. The Staff Paper itself flags potential MCP inflation.	Any use of above-cap demand bids should be pilot-tested, capped, transparently reported and sunset unless proven not to distort market prices.

9	RA Capacity Market / dispatch and scheduling (Para 27 Option 1)	Both generator and discom bid into DAM/RTM and settle at MCP, while capacity charge is paid separately.	Clarify the settlement waterfall between capacity charge, energy market revenue, bilateral settlement, deviation charges and ancillary dispatch. Define who receives congestion rents, imbalance exposure and energy-market upside/downside.	Without a clear settlement design, there is risk of double payment, disputes, and uncertainty over whether capacity providers or buyers bear energy-market price risk.	Include illustrative settlement examples for low MCP, high MCP, non-clearance, transmission congestion, reserve dispatch and curtailment cases.
10	RA Capacity Market / stress hour obligation (Para 27)	Capacity providers may be mandated to participate and be cleared in market during peak/stress hours notified by NLDC.	Replace 'must be cleared' with a 'must-offer and must-be-available' obligation. Market clearance is not fully within the seller's control and can be affected by exchange algorithms, congestion, demand bids and system constraints.	A capacity provider can offer available capacity in good faith yet fail to clear for reasons beyond its control. Penalising non-clearance would create uncontrollable risk and raise bid prices.	Obligation should be assessed against availability, valid offer submission, telemetry, deliverability and response to dispatch instruction, not merely market clearing outcome.
11	RA Capacity Market / stress hour methodology (Para 22, 27, 39)	NLDC would notify peak/stress hours, but methodology is not specified.	NLDC should publish a transparent stress-hour methodology, including advance notice period, maximum number of stress hours per month/year, objective triggers, ex-post publication, and audit process.	Predictability is necessary for storage SOC management, demand-response readiness, maintenance planning and penalty risk assessment.	Stress events should be notified using pre-defined reliability indicators such as reserve margin, forecast peak, net-load ramp, transmission constraints or frequency/security conditions.
12	RA Capacity Market / penalty design (Para 27 and 39)	Failure to clear during stress periods attracts penalty at 1.5 times discovered capacity charge.	Create a proportionate performance penalty framework with monthly/annual caps, cure periods, exclusion of uncontrollable events, and positive incentives for over-performance.	A flat 1.5x penalty could be disproportionate for storage, RE+ESS, hydro and assets affected by grid constraints. Excessive downside risk will be priced into bids or deter participation.	Penalties should apply only to controllable non-performance after accounting for grid curtailment, transmission congestion, SLDC/RLDC instructions, force majeure, exchange/system outage, fuel supply event outside generator control and prior reserve dispatch.
13	RA Capacity Market / RE+ESS eligibility (Para 27)	Staff Paper expects RE projects to offer capacity by firming generation with ESS and recommends a technology-agnostic market.	Explicitly define eligibility and performance standards for RE+ESS/hybrid projects, including firm MW obligation, duration in hours, availability window, permitted charging source, forecasting tolerance, and treatment of renewable curtailment.	RE+ESS can provide firm capacity but only if the product is defined around deliverable MW over specified time windows. A generic MW obligation can unfairly penalise VRE variability.	Contracted capacity should be based on accredited firm capacity, not RE nameplate; CERC should provide separate templates for standalone BESS, RE+ESS, hybrid and RTC-type products.
14	RA Capacity Market / standalone BESS (Para 27)	Staff Paper does not provide detailed standalone BESS participation norms.	Include standalone BESS as an eligible capacity, reserve and secondary-market resource with degradation-adjusted availability norms, augmentation obligations, SOC management rules and clear metering/telemetry standards.	BESS can provide fast response, ramping, reserves and peak support, but commercial viability depends on degradation, cycling and augmentation treatment.	Define MW, MWh duration, round-trip efficiency, maximum equivalent cycles, response time, minimum SOC reserve, charging rights, degradation compensation and augmentation schedule.
15	RA Capacity Market / deliverability (Para 25-27, 36-39)	Staff Paper focuses on capacity MW but does not specify deliverability tests and transmission constraints.	Capacity should count toward RA only if it is deliverable to the relevant load zone or control area under credible transmission conditions. Locational/zonal capacity accreditation should be considered where congestion is material.	A MW of capacity that cannot be delivered during stress hours does not provide resource adequacy. Transmission constraints can also drive market non-clearance and unfair penalties.	Add deliverability criteria linked to GNA/ISTS/STU capacity, outage planning, congestion zones and inter-regional transfer capability.
16	RA Capacity Market / payment security (Para 27 Option 1-3)	Capacity payments would be borne by discoms/deficient entities, with central agency involvement in Option 3.	Require robust payment security: LC/escrow, payment security fund, default waterfall, regulated pass-through and step-in/novation rights for long-term capacity contracts.	Discom payment delay risk is a key bankability concern. Capacity contracts without enforceable payment security may not attract competitive bids or low tariffs.	Central agency contracts should not transfer discom credit risk to capacity providers without a clear payment security mechanism.
17	RA Capacity Market / contract exit and transfer (Para 1, 27, 39)	Original draft suggested flexibility to relinquish obligations under capacity market contracts.	Allow transfer/novation/relinquishment only under defined conditions, with replacement capacity, advance notice, exit compensation, and approval by the relevant counterparty/market operator.	Unrestricted exit reduces bankability and undermines RA compliance; however, controlled transfer improves liquidity and portfolio optimisation.	Create a standardized transfer/novation framework and secondary capacity registry rather than unilateral exit.
18	RA Capacity Market / legacy PPAs (Para 26-27)	Existing PPAs are inherently capacity contracts with scheduling rights.	Provide transition rules for existing PPAs, including voluntary participation, grandfathering of scheduling rights, SERC approval process, and no unilateral impairment of existing contracts.	A capacity market cannot be implemented cleanly without addressing legacy fixed-cost PPAs and state procurement approvals. Contract impairment would create litigation risk.	Existing assets should participate through optional secondary capacity products or bilateral settlement mechanisms unless parties consent to amend PPAs.

19	RA Capacity Market / market power (Para 27, 37, 39)	Market-based capacity procurement is proposed but market power mitigation is not specified.	Establish market monitoring, withholding rules, offer caps, concentration screens, affiliate disclosure, and penalties for economic/physical withholding.	Capacity markets are vulnerable to scarcity-driven market power, especially if deliverability zones are constrained or few flexible resources exist.	Designate a market monitor and publish post-auction reports on concentration, cleared capacity, clearing price, unavailable capacity and withheld capacity.
20	RA Option 2 / bilateral settlement (Para 27 Option 2)	Option 2 retains two-part tariff contracting but shifts dispatch to market with bilateral adjustments against contracted tariff.	Option 2 should be further developed as a lower-disruption transition pathway, provided that contract-for-difference settlement, scheduling rights, deviation responsibility and regulatory pass-through are clearly defined.	It may preserve bankability while enabling market-based dispatch. However, settlement complexity and SERC approval requirements need to be resolved before implementation.	CERC should issue a model contract/settlement example and allow pilots with voluntary participants before mandating this structure.
21	Residual RA Capacity Market / backstop role (Para 27 Option 3)	A central agency may run a residual RA auction for discoms with RA shortfall.	Support residual RA capacity market as a backstop for deficient entities, but it should not dilute each discom's primary RA procurement obligation.	A residual market can address shortfalls and coordination failures, but if overused it may weaken state-level planning discipline and increase central procurement risk.	Trigger residual procurement only after transparent deficiency assessment, SERC-approved RA plans, and failure to procure within prescribed timelines.
22	Residual RA Capacity Market / central agency risk (Para 27 Option 3)	Central agency contracts with capacity providers while discoms pay proportionate capacity charge.	Define the central agency's role, counterparty status, payment liability, default remedies, regulatory pass-through and credit support before residual auctions are launched.	If the central agency is only an intermediary while discoms default, developers will price credit risk. If the agency assumes payment risk, its funding and risk allocation must be clear.	Add a central payment security mechanism funded by participating deficient entities before auction participation.
23	Residual RA Capacity Market / procurement horizons (Para 27 Option 3)	Option 3 provides 10-15 year contracts for residual shortfall and suggests secondary market for 1-3 year shortfall.	Create separate procurement windows: long-term new-build auctions (T-4/T-3), medium-term existing capacity auctions (1-3 years), and seasonal/monthly deficiency products.	Different lead times are needed for new generation, storage, demand response and existing capacity. A single residual auction design will not solve all RA shortfalls.	Central agency should publish a forward residual procurement calendar and deficiency forecasts.
24	Reserve Capacity Market / assessment (Para 36)	NLDC shall allocate reserves as per IEGC; States shall procure reserves and demonstrate compliance; NLDC identifies state-wise shortfall.	Require NLDC to publish an annual and seasonal reserve adequacy report covering secondary and tertiary reserve requirement, state-wise allocation, shortfall, procured reserves, and procurement cost.	Transparent reserve visibility helps states plan procurement and helps developers assess investable reserve products.	Publish at least one-year-ahead reserve forecasts and monthly updates, with data confidentiality safeguards where required.
25	Reserve Capacity Market / phased implementation (Para 31-33)	Staff Paper recommends advance procurement of reserves during the transition until RA framework matures.	Advance reserve procurement should be introduced as a time-bound transition mechanism, reviewed annually, and calibrated to avoid duplicating AS/energy market revenues.	Reserve procurement is needed during transition, but permanent out-of-market procurement could distort energy and ancillary markets if not calibrated.	Start with pilot auctions in regions/seasons with demonstrated reserve shortfall and publish lessons before national roll-out.
26	Reserve Capacity Market / product definition (Para 37)	Separate auctions are proposed for secondary and tertiary reserves.	Define reserve products in operational terms: up/down direction, response time, ramp rate, sustained duration, minimum activation volume, telemetry, metering, availability test, start-up/no-load cost and restoration time.	Without standard product definitions, resources with different capabilities cannot be compared fairly and procurement may not produce reliable reserves.	Include separate product specifications for SRAS-Up, SRAS-Down, TRAS-Up, TRAS-Down, fast-response storage, and longer-duration reserves.
27	Reserve Capacity Market / eligibility (Para 37)	Eligibility to meet CERC Ancillary Services Regulations criteria.	Explicitly include standalone BESS, pumped storage, hydro, flexible thermal/gas, demand response, aggregated distributed energy resources and qualified aggregators, subject to telemetry and performance criteria.	Competition and reserve adequacy improve when fast-response and aggregated resources participate. Storage and demand-side resources are often better suited for reserves than conventional generation.	Eligibility should be technology-neutral but capability-tested; aggregation thresholds should be practical for C&I loads and distributed storage.
28	Reserve Capacity Market / auction tenor (Para 37)	Auction frequency and contract duration are proposed as once a year and one year.	Use one-year contracts for existing resources, but allow 3-5 year reserve capacity contracts for new flexible capacity and 10-15 year contracts where dedicated BESS or pumped storage is built for reserve/RA services.	One-year contracts do not provide sufficient revenue visibility for new flexible capacity. Longer tenor may be needed to create new reserves, not only optimise existing surplus capacity.	Create separate auctions for existing capacity and new-build reserve capacity with different lead times and tenors.
29	Reserve Capacity Market / demand curve and bid cap (Para 37)	Demand curve is proposed as Net CONE plus 10% to set bid cap and downward sloping demand curve.	Avoid an arbitrary 10% uplift unless backed by reliability-value analysis. Bid cap and demand curve should reflect reserve shortage cost, reliability standard, technology-specific Net-CONE and market power considerations.	An arbitrary cap can either fail to attract reserves or overcharge consumers. Reserve capacity value is not identical to RA capacity value.	Publish the methodology for reserve Net-CONE, expected AS/energy revenue offset and scarcity/reliability parameters.

30	Reserve Capacity Market / NLDC first right (Para 37)	NLDC shall have the first right of scheduling and dispatch of selected reserve capacity.	Clarify how NLDC first-right dispatch interacts with existing PPAs, energy market bids, state schedules, AS obligations and bilateral commitments.	Priority ambiguity can lead to disputes, double scheduling, opportunity-cost under-recovery and deviation exposure.	Issue detailed scheduling priority rules and settlement examples, including compensation when reserve commitment prevents energy-market participation.
31	Reserve Capacity Market / commitment charge (Para 37 Scenario 2)	If capacity is requisitioned and scheduled but not dispatched, provider receives capacity charge and commitment/holding charge as	Define commitment/holding charge methodology upfront, including start-up cost, no-load cost, minimum run cost, opportunity cost, SOC reservation cost for storage, and hydro water value where applicable.	Investors cannot price reserve offers if a material compensation component is left undefined. Storage and hydro particularly need opportunity-cost recognition.	The methodology should be part of auction documents or regulations before bidding.
32	Reserve Capacity Market / cost allocation (Para 37)	Capacity charge is recovered from reserve-deficient states; energy/compensation and commitment charge from DSM & AS pool, with deficits allocated under DSM	Cost allocation should be transparent, beneficiary/causer-pays to the extent possible, and limited to reserve-deficient states for capacity shortfall, with clear pass-through rules and dispute resolution.	Broad socialisation could reduce incentives for states to procure reserves. Conversely, unclear recovery from DSM & AS pool may create underfunding risk.	Publish state-wise reserve shortfall computation, allocation methodology, monthly bills, pool balance and reconciliation.
33	Reserve Capacity Market / penalties (Para 37)	Failure to participate in AS market attracts penalty at 1.5x(discovered capacity charge + AS price).	Use performance scoring with proportional penalties and caps rather than a single flat multiplier. Exclude uncontrollable events and recognise partial availability/performance.	Reserve resources may be unavailable due to grid instructions, telemetry outages not attributable to resource, prior dispatch, SOC depletion after system instruction, or force majeure.	Penalty should be capped at monthly capacity payment or a defined annual percentage; chronic non-performance may trigger de-rating, suspension or forfeiture.
34	Secondary Short-Term Capacity Market / legal transferability (Para 38-39)	Existing surplus and deficit entities can trade capacity through market platform.	Clarify whether capacity rights under existing PPAs are transferable, and whether generator consent, discom consent and SERC approval are required for short-term capacity sale.	Existing PPAs often bundle capacity payment, scheduling rights, energy charge and fixed-cost recovery. Trading capacity without legal transfer rules can cause disputes.	Create standard tripartite/novation terms and confirm treatment of fixed-charge liability during the traded period.
35	Secondary Short-Term Capacity Market / product design (Para 39 Option 1)	Market platform auctions every three months for one-month/three-month contracts.	Standardize products by delivery month/season, peak block, non-solar peak, evening peak, weekend/weekday, reserve-linked capacity and firm duration. Add 6-12 month forward products after pilot.	Standard products improve liquidity and match India's seasonal/diurnal adequacy needs. Three-month products alone may not provide enough visibility for deficit discoms or storage operators.	Begin with monthly and quarterly standardized products, then introduce seasonal and 6-12 month products based on liquidity.
36	Secondary Short-Term Capacity Market / deliverability and transmission (Para 38-39)	Short-term capacity trading is proposed to make surplus capacity visible to deficit entities.	Capacity trades should be subject to transmission deliverability, GNA/short-term open access availability, congestion management and regional/zonal constraints.	A traded capacity product has little reliability value if energy cannot be delivered when needed. Deliverability uncertainty can also create unfair penalty exposure.	Market platform should display available transmission capability or zonal deliverability before auction clearing.
37	Secondary Short-Term Capacity Market / Option 2 two-part bid (Para 39 Option 2)	Option 2 uses two-part bids comprising capacity charge and energy charge.	Option 2 may be more suitable where buyers need price certainty for energy as well as capacity, but the settlement design must define variable charge, market MCP, bilateral adjustment, deviation charges and non-scheduling treatment.	Capacity-only products may not protect buyers against high variable-cost exposure, while two-part products can better replicate PPA economics for short tenors.	CERC should pilot both capacity-only and two-part products and compare liquidity, price discovery and consumer cost before choosing a preferred design.
38	Secondary Short-Term Capacity Market / storage operational limits (Para 39)	Capacity holders must clear during peak/stress hours; storage availability depends on prior dispatch/SOC.	For storage and hydro, performance obligations should account for prior dispatch instructions, charging opportunities, water/SOC constraints and restoration time.	Storage cannot simultaneously provide energy, reserve and capacity without defined priority and replenishment rules. Prior system dispatch can deplete SOC before a stress event.	Define SOC reservation, recharge windows, dispatch priority and penalty relief where non-availability follows NLDC/RLDC/SLDC dispatch instructions.
39	Cross-cutting / demand response (Para 12, 17, 37, 39)	International examples allow demand response, but India design discussion does not sufficiently elaborate demand-side capacity.	Recognize demand response, load curtailment, industrial flexibility, EV charging flexibility and qualified aggregators as capacity resources, subject to measurement and verification.	Demand-side capacity can reduce peak procurement needs and consumer costs, especially for short-duration stress events.	Develop baseline, M&V, telemetry, aggregation threshold and penalty rules for demand-side capacity.
41	Cross-cutting / environmental and transition risk (Para 24-25)	Capacity markets are intended to ensure adequacy, but may also retain or incentivise high-emission capacity.	Capacity market design should be reliability-focused but consistent with emissions norms and India's clean-energy transition. Avoid long-term lock-in of inflexible or non-compliant high-emission assets unless needed for reliability and no lower-cost alternative exists.	A poorly designed market may prolong inefficient capacity and increase consumer cost. Clean flexibility resources need a fair route to participate.	Add eligibility conditions for statutory environmental compliance, flexibility capability and retirement/transition treatment for ageing assets.

43	Cross-cutting / consumer affordability (Para 23-24)	Staff Paper argues capacity market can keep MCP under control and may avoid higher costs from scarcity.	Require ex-ante and ex-post consumer cost-benefit assessment before large-scale implementation, including impact on retail tariffs, market MCP, discom power purchase cost and reliability metrics.	Capacity payments are ultimately borne by consumers. Consumer benefit should be demonstrated through avoided scarcity, improved reliability or reduced emergency procurement.	Publish regulatory impact analysis and annual cost-benefit report comparing capacity payments with avoided load-shedding, Section 11 procurement, HP-DAM scarcity costs and reserve shortfall costs.
	Cross-cutting / transparency and data	Market designs require data on RA shortfalls, reserve shortage, stress hours, capacity prices and performance.	Mandate periodic publication of non-confidential data: RA positions, capacity accreditation factors, Net-CONE assumptions, auction demand curves, cleared prices/volumes, stress-hour events, performance failures and penalties.	Transparency reduces regulatory uncertainty, supports competitive bids and enables public evaluation of consumer cost and reliability benefits.	Create an annual Capacity Market Monitoring Report by CERC/NLDC.
	Cross-cutting / regulatory coordination	Implementation will interact with CERC Power Market Regulations, IEGC, AS Regulations, DSM Regulations, SERC RA regulations, PPAs and exchange rules.	Before notification, CERC should issue a consolidated implementation paper mapping required amendments, institutional roles, settlement systems and timelines.	Fragmented changes can create gaps between central market design and state procurement approvals.	Set up a joint CERC-CEA-NLDC-SERC working group and publish model regulations/contracts for state adoption.
44	Cross-cutting / dispute resolution	The Staff Paper does not define dispute timelines for capacity accreditation, penalties, settlement and compliance disputes.	Provide expedited dispute resolution mechanisms and timelines for auction disputes, capacity accreditation challenges, penalty appeals, payment defaults and performance assessment.	Capacity markets involve high-value obligations and time-sensitive settlement. Slow dispute resolution increases risk premium.	Create an operational review committee for first-level disputes, with escalation to CERC/SERC as applicable.
45	Recommended submission position	CERC has invited comments on RA capacity market, reserve capacity market and secondary short-term capacity market.	Recommended position: support Option 3 residual/backstop RA market and reserve capacity pilot first; develop secondary capacity market with registry and deliverability; treat Option 1 full RA capacity market only after pilots and impact assessment.	This balances reliability improvement with bankability, consumer affordability and implementation readiness.	Include this as the first paragraph in stakeholder submission to CERC.