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Ref: GRID-INDIA/NLDC/CERC/June-26/ **Date:** 17th June 2026

सेवा में,
सचिव,
केन्द्रीय विद्युत विनियामक आयोग
6th, 7th एवं 8th फ्लोर, टावर बी, वर्ल्ड ट्रेड सेंटर
नौरोजी नगर, नयी दिल्ली, 110029

विषय: Comments/Suggestions on the Staff Paper on "Capacity Market for Electricity in India"

महोदय,

The Hon'ble Commission has notified the Staff Paper on "Capacity Market for Electricity in India" dated 29th April 2026.

The Comments/Suggestions on behalf of the Regional Load Despatch Centres (RLDCs) and National Load Despatch Centre (NLDC) on the said Discussion Paper are enclosed herewith for kind perusal and consideration of the Hon'ble Commission.

सधन्यवाद,

भवदीय,

17/06/2026

(मनोज कुमार अग्रवाल)
कार्यकारी निदेशक, रा॰भा॰प्रे॰कें॰

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Grid Controller of India Limited
(A Govt. of India Enterprise)

Date – 17-06-26

Suggestions on behalf of RLDCs/NLDC on CERC Staff Paper on Capacity Market for Electricity in India

Introduction -

Grid-India welcomes the CERC Staff Paper on Capacity Market for Electricity in India. The paper raises key issues on resource adequacy, reserve procurement, and short-term capacity trading that is needed to be address systematically. These comments are offered with the objective of strengthening the analytical and operational framework of the proposals before they are advanced to regulatory consideration.

I. Foundational Design Considerations

a) The Missing Money Problem and the Role of Price Caps

The Staff Paper correctly identifies the "missing money problem" as one of the primary motivations for a capacity market. Steven Stoft (2002) and Cramton, Ockenfels & Stoft (2013) explain that the missing money problem is in part associated with administratively suppressed price caps in energy markets, though it also reflects broader market design and demand-side limitations. When energy price caps are set below VoLL, generators may be unable to recover fixed costs through energy market revenues alone, which is one reason capacity markets are introduced. If the price cap is raised closer to VoLL, the missing-money gap narrows, although the extent to which capacity payments become smaller or less necessary depends on the overall market design.

The Staff Paper may consider examining the role of existing price caps in the DAM and RTM (including the current DAM price ceiling of ₹10/kWh) in the context of resource adequacy and the missing money problem. Before finalising the capacity market design, an analysis should be carried out. It should assess whether the current price cap reflects India's Value of Lost Load (VoLL).

It should also examine whether a calibrated increase in the price cap is needed. This increase could act as a substitute for a capacity market or complement it.

Such an approach may help reduce the missing money problem. It could also involve lower institutional complexity and implementation costs.

b) The Four Pillars Must Precede the Capacity Market

Sally Hunt, in *Making Competition Work in Electricity* (2002), establishes that functioning competitive electricity markets require four foundational pillars to be operational: *scheduling and dispatch, imbalance settlement, congestion management, and ancillary services*. All four pillars needs to be operational at both the inter-state and intra-state levels in India before market-based capacity mechanisms can function effectively.

As of 2026, intra-state SAMAST implementation (Scheduling, Accounting, Metering and Settlement of Transactions) remains incomplete in many of the States. Without time-block-wise metering and settlement at the intra-state level, generators embedded within State systems cannot participate in or be held accountable under capacity market framework.

It is also pertinent to mention here that large pumped storage plants such as Kadamparai, Srisailam, Purulia are embedded inside the state systems. These plants are very good potential candidates for utilization under ancillary services. However, it has not been possible to harness these plants under the ancillary services because of various reasons which include lack of scheduling, time-block wise metering, accounting and settlement mechanisms inside the state.

II. RA Obligation Capacity Market — Design Issues

a) The Must-Offer Obligation during declared Stress Hours

The Staff Paper proposes, in all three RA Obligation options, that capacity-contracted generators must bid into the DAM/RTM as "price takers" during NLDC-notified peak/stress hours. This is a necessary but insufficient condition for market discipline. International capacity markets impose a year-round must-offer obligation — not limited to stress periods. In PJM, all Capacity Performance resources must offer capacity in every Reliability Pricing Model auction and must offer into the Day-Ahead Energy Market during the entire delivery

year. GB capacity holders similarly must remain available and submit Physical Notifications throughout the delivery period.

It is recommended that the framework establish a continuous must-offer obligation as the baseline condition for all capacity-contracted resources, with the stress-hour price-taker requirement serving as an additional layer of obligation during declared scarcity periods.

A related concern arises from the informational design of the stress hour declaration. The public notification of stress hours by NLDC constitutes market-sensitive information, and its disclosure framework requires careful structuring.

Further, DISCOMs procure capacity primarily to meet their own peak demand requirements. However, the stress hours declared by NLDC may pertain to an all-India system condition and may not necessarily align with the peak demand period of a particular DISCOM. Therefore, it would be more appropriate for the identified stress hours to coincide with the respective DISCOM's stress or peak demand hours.

b) Scheduling Rights Transition:

Option 2 proposes that discoms retain scheduling rights "until the day-ahead market window opens". This aligns with the self-scheduling practices arising from two decades of Availability Based Tariff regime.

In India's current framework, discoms submit advance Inter-state schedules through the RLDCs — a multi-revision cycle. The paper proposes that the discom's bilateral scheduling rights cease when the "DAM window opens," but does not specify whether the discom's advance schedule submitted to the RLDC before noon becomes the reference position for bilateral settlement, regardless of the DAM-cleared outcome.

c) Distortionary risk due to the Demand Curve Above Price Cap:

The Staff Paper's proposal to draw the discom's demand curve "slightly above the price cap" to guarantee supply of contracted capacity is a workable short-term fix for the free-rider problem. But it carries a material market-distortion risk. If multiple discoms — particularly those with large contracted portfolios — simultaneously draw their demand curves above the price cap for their entire contracted volume, the aggregate effect would be to structurally drive

the MCP toward the price cap in periods of any supply-demand tightness. Steven Stoft has shown that administrative price interventions in electricity markets — whether caps on the upside or guaranteed floors on the downside — tend to produce second-order distortions.

d) Unit Commitment issues

Unit commitment (UC) is the decision of which generating units to switch on, when, and for how long, over a planning horizon — typically 24 to 48 hours ahead. It is distinct from economic dispatch, which assumes units are already committed and only optimises their output levels. UC is far more complex because it involves binary on/off decisions combined with continuous output variables, creating a mixed-integer optimisation problem. Further it introduces following challenges -

Generating units have non-convex cost characteristics — specifically, start-up costs, no-load costs (the cost of running a unit at zero output), and minimum generation levels (technical minimums). These costs cannot be recovered through a standard uniform market clearing price because the marginal cost of the last unit dispatched does not cover the fixed commitment costs of units that must run regardless of output. This causes "missing money" problem at the unit commitment level.

Because uniform market clearing prices cannot compensate for non-convex costs, market operators must make out-of-market "uplift" or "make-whole" payments to generators whose commitment costs are not recovered through market revenues. These payments:

- Distort price signals — the published MCP does not reflect true system costs
- Create adverse bidding incentives — generators have an incentive to overstate start-up or no-load costs to maximise uplift recovery
- Are non-transparent — uplift amounts are often socialised across all consumers without clear attribution

In PJM and other US markets, uplift payments run into hundreds of millions of dollars annually and are a persistent source of market design controversy.

e) Settlement Architecture and the Contract for Difference Analogy under Option 2:

Option 2 of the RA Obligation Capacity Market proposes a two-leg settlement structure: the energy leg is settled at the Market Clearing Price (MCP) through the power exchange, while

the bilateral leg — representing the difference between the MCP and the contracted total cost — is settled directly between the discom and the generator outside the market.

This structure is, analogous to a Contract for Difference (CfD), a mechanism widely deployed in Great Britain (GB) for firming up renewable energy investments. In GB the generator receives the difference between a strike price and the reference market price, or pays back the surplus when the market price exceeds the strike.

While the CfD structure has demonstrated merit in international contexts, its successful operation in India depends on a settlement infrastructure that is currently absent in India. Following foundational design elements warrant the Commission's attention before this option is advanced.

Settlement Timeline for the Bilateral Leg: The Staff Paper does not specify the frequency or timeline for settlement of the bilateral leg — whether it is to be settled daily, monthly, or quarterly. This has direct implications for the working capital requirements of generators, particularly independent power producers without large balance sheets.

Absence of a Central Clearing Counterparty: In Great Britain, CfD settlement is guaranteed by the Low Carbon Contracts Company, a government-owned entity. In PJM, all capacity market settlements are conducted through PJM's central settlement system, with financial assurance requirements imposed on all market participants.

In India, while CERC Power Market Regulations 2010 provided the regulatory framework for a Clearing Corporation. Further CERC Power Market Regulations 2020 mandated power exchanges to carry out the Clearing and Settlement in accordance with the Payment and Settlement Systems Act, 2007 (PSSA 2007). PSSA 2007, inter-alia, provides that the payment and settlement related activities of Exchanges (excluding stock exchanges) would be under the purview of the Reserve Bank of India (RBI).

However, no such Clearing Corporation has been established to date. The bilateral leg needs to ensue institutional infrastructure of a central clearing counterparty that provides settlement guarantee, margining, and default management.

III. Reserve Capacity Market — Operational and Technical Issues

a) Terminology: Requisitioned vs. Scheduled vs. vs. Dispatched

As per prevailing scheduling practice any quantum scheduled by the system operator would by definition be dispatched. The dispatch scenario framework in Paragraph 37 of the Staff Paper uses the term "scheduled but not dispatched" in Scenario 2. The distinction the Staff Paper is attempting to draw is between a resource that is committed and held in synchronised reserve (spinning reserve) and one that is physically dispatching energy. Using "scheduled" to mean "committed but not generating" introduces ambiguity. These are standard operational categories under the IEGC and CERC Ancillary Services Regulations, and the framework may use these established terminologies consistently.

b) Technology Differentiation and Net-CONE Calculation

The Staff Paper proposes a single Net-CONE-based demand curve for the Reserve Capacity Market. However, Net CONE varies significantly across technologies because capital costs, fixed operating costs, and energy/ancillary-service revenue opportunities differ. Capacity-market design literature also warns that a single uniform clearing price may fail to reflect these differences, potentially favouring lower-cost incumbent resources over newer, more flexible entrants.

In this regard, CERC, being the sector regulator and having access to benchmark cost data for various generation technologies, may determine and notify the Gross CONE for different technology categories. Thereafter, NLDC may undertake the assessment of Net CONE by accounting for the expected revenues from the energy market and ancillary services market.

In case multiple technologies are considered for adequacy planning or capacity market design, a clear methodology would also be required for apportioning the ancillary service revenues attributable to each technology in order to arrive at the respective Net CONE.

It is suggested that a sample calculation may be provided for computation of Gross & Net-Cone.

c) Technical Constraints and Reserve Eligibility

The issue of compliance with technical minimum, ramp limits may not always allow thermal generators to participate effectively in reserves market. In contrast, technologies such as Energy Storage Systems (ESS) and gas-based generating stations, owing to their fast ramping and flexible operating characteristics, may be better suited for participation in such

mechanisms. Therefore, the framework may need to define the eligible technologies and the methodology for assessing and confirming technical ability for participation in reserve market.

Grid-India has prepared Functional Requirements and Commercial Mechanism for Procurement of Reserves from Battery Energy Storage Systems (BESS) Participating in Secondary Reserve Ancillary Services (SRAS). Same is attached herewith as Annexure-1.

d) India's Existing Experience in the Crunch Period Procurement Scheme

In past years India has been operationalising elements of a short-term capacity market through advance procurement of peaking capacity during summer crunch periods. Since 2023, the Ministry of Power has annually designated NVVN as Nodal Agency to conduct competitive procurement (e-Reverse Auction) of gas-based and, from 2026, technology-agnostic peaking resources, based on demand-supply assessment. The 2026 scheme targeted 2000 MW (12,000 MWh/day) during non-solar peak hours (18:00–04:00 hrs) for April–June 2026.

NVVN handled commercial contracting, selling of power through bilateral or exchange markets and payment. NLDC held right of scheduling and dispatch, confirming resource activation on D-1 through ancillary services. Generators not called on a given day were released to sell freely in bilateral or exchange markets — a feature that closely mirrors the Reserve Capacity Market's Scenario 3 dispatch design.

The commercial framework included a single-part Rs/kWh tariff (fixed for the contract period), a Minimum Guaranteed Off-take (MGO) of 300 MU over 50 crunch days providing minimum revenue certainty. The detailed scheme is attached as Annexure-II.

Despite this operational framework and a supply-demand need, the 2026 tender received zero bids even after two deadline extensions.

IV. Secondary Short-Term Capacity Market — India-Specific Structural Considerations

a) PUSHP Portal Experience: Behavioural and Contractual Barriers

The Staff Paper's proposal for a short-term capacity market is premised on the assumption that discoms with surplus capacity will voluntarily offer it for secondary trading. Grid-India's operational experience with the PUSHP portal — which already provides a mechanism for

surrendering or reallocating power — indicates that DISCOMs are structurally reluctant to release tied-up capacity, even when temporarily surplus, due to concerns about future demand uncertainty, supply security, and contractual obligations.

b) The "Demand Curve Above Price Cap" Mechanism and Price Formation Integrity

In the short-term capacity market context, the paper envisages double-sided bidding and uniform price step auction. This mechanism to allow placing demand curve above price cap would systematically override competitive price discovery. The capacity market's primary economic function, as Stoft emphasises, is to produce a durable price signal for new investment. A design that structurally suppresses price formation dilutes this purpose.

c) Financial Structure and Settlement Risk under option 2

Option 2 introduces a pay-or-schedule obligation — the buyer pays the capacity charge regardless of whether scheduling is exercised. This is economically equivalent to the buyer purchasing a call option on physical delivery, with the capacity charge as the option premium. For this structure to produce efficient outcomes, the option premium (capacity charge) must reflect the optionality value, which a uniform price step auction — without option pricing methodology — cannot accurately determine. Moreover, the bilateral settlement leg (the difference between contracted total cost and MCP) introduces credit risk. India has no Clearing Corporation or central counterparty for financial settlement of energy contracts, and that the CERC Power Market Regulations 2020 provide the regulatory framework for such a corporation that has yet to be established.

V. Common Design Elements: Price Caps, Penalties, and Incentive Structure

a) Price Cap Design and the Missing Money Nexus

All three capacity market segments use a Net-CONE-based bid cap. The robustness of this bid cap depends critically on the quality of the Net-CONE estimate, which in turn depends on the expected energy and ancillary services market revenues. If India's energy market price cap is not calibrated to VoLL, the Net-CONE will be systematically overstated — resulting in capacity market payments that are larger than necessary to solve the missing money problem, effectively transferring additional revenue to generators at consumer cost.

b) Penalty Structure: Flat Rate vs. Scarcity-Indexed

Flat 1.5× penalty across all three markets may be insufficient during genuine grid stress — scarcity-indexed penalties would be more effective.

PJM's Capacity Performance framework ties penalties to the Net Cost of New Entry (Net CONE), scaled by the magnitude of performance shortfall during Performance Assessment Intervals (PAIs). This create a penalty structure that is directly proportional to both the shortfall volume and the benchmark cost of new capacity. Therefore, more reflective of the system's reliability cost than a flat multiplier.

A scarcity-indexed penalty — where the penalty rate escalates as a function of the system's prevailing scarcity level (e.g., a multiplier on the DAM/RTM MCP during the non-delivery period) — would more accurately reflect the harm caused by non-performance and create stronger incentives for genuine capacity availability during stress.

c) Over-Delivery Incentives: A Structural Absence

The three proposed markets do not contain any provision for over-delivery incentives. GB's Capacity Market pays capacity providers for delivery above contracted levels during system stress events. PJM's Capacity Performance framework pays bonus Performance Credits to resources that outperform, funded by the penalties of underperformers. The absence of over-delivery incentives in the Indian framework means that rational capacity providers will target delivery precisely at contracted levels during stress — providing no buffer above the contracted minimum.

d) Voluntary versus Mandatory Participation:

The present formulation of the Indian Electricity Market has a voluntary participation model. The Discussion Paper suggests moving to a mandatory Power Exchange based despatch model for the capacity contracted through resource adequacy capacity market.

This issue of mandatory versus voluntary participation through Power Exchanges was thoroughly debated when the Power Exchanges were getting introduced in the country in 2008. The relevant extract from the CERC Order in Suo-Motu Petition No. 155/2006 dated 18th January 2007 is quoted below.

"16. The Commission is of the considered opinion that the main objective of proposing establishment of PX in India is to provide one more option to the utilities/entities and mandating participation in power exchange shall not be in consonance with the said objective. We would like participation in the power exchange to be voluntary with full freedom to individual utility/entity to decide about it depending on the perceived benefits vis-à-vis other options."

In this context, it is pertinent to recall that M/s ECC of USA undertook a comprehensive study of the Indian power system in the early 1990s, sponsored by the World Bank and the Asian Development Bank. Their Report on Bulk Power Generation and Transmission Tariff was submitted in February 1994. The Report recommended the introduction of the Availability Based Tariff (ABT) structure for central sector generating stations, along with decentralised scheduling and despatch in keeping with India's federal structure. The Government of India accepted these recommendations in principle in November 1994, with ABT subsequently implemented with effect from 1st July 2002. A significant recommendation in the ECC Report was the adoption of 'decentralized' scheduling and despatch in the country keeping in view the federal structure of the country and the fact that electricity is a concurrent subject. The present Indian Electricity Market design has evolved over the last two decades keeping the federal structure, decentralized scheduling and despatch, and voluntary participation.

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Annexure-I

Functional Requirements and Commercial Mechanism for Procurement of Reserves from Battery Energy Storage Systems (BESS) Participating in Secondary Reserve Ancillary Services (SRAS)

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1. SHORT TITLE, EXTENT AND COMMENCEMENT

1.1 These provisions shall be called the "Functional Requirements and commercial mechanism for Procurement of Reserves from Battery Energy Storage Systems (BESS) Participating in Secondary Reserve Ancillary Services (SRAS)".

1.2 They shall apply to all BESS whose reserves are contracted by GRID-INDIA for provision of Ancillary Services under the approved framework.

1.3 They shall come into force from the date as may be approved by the Central Electricity Regulatory Commission (CERC).

2. SCOPE AND APPLICABILITY

2.1 These provisions specify the functional/technical requirements and commercial mechanism for advance procurement of Secondary Reserve Ancillary Services (SRAS) from BESS.

2.2 The reserves committed for participation in Secondary Reserve Ancillary Services (SRAS) shall not be simultaneously committed under any other contract for the same capacity during the contract period.

2.3 Where the same BESS capacity has been previously committed/owned under any other contract, the BESS provider may participate in SRAS for the specified contract period only after obtaining a no-objection certificate (NOC) from the concerned existing contract holder, in accordance with the tender conditions.

2.4 The committed reserve from BESS shall be capable of providing up and down regulation under SRAS, as and when requisitioned by the System Operator.

3. DEFINITIONS

(a) "Battery Energy Storage System (BESS)" means a stationary system connected to the electricity system which is used to store electrical energy by means of electrochemical materials, and typically includes batteries, power conversion system and BMS.

(b) "Battery Management System (BMS)" means a system which control on batteries in order to obtain safe operation, and also balances the energy of batteries and monitors the status thereof.

(c) "Committed Reserve" means the quantum of capacity, in MW and MWh, of a BESS Project contracted for Ancillary Services under the applicable agreement.

(d) "Battery Container" means a container in which battery racks are placed.

(e) "Battery Module" means a string of series connected cells placed in an encasing.

(f) "Battery Rack" means a string of series connected Battery Modules placed in a container.

(g) "C Rate" means the inverse measure of time duration over which a battery can charge and discharge at its maximum rated power.

(h) "Cycle" means the charging of a Battery from its Depth of Discharge (DoD) level to its peak charging level and again discharging to its DoD level.

(i) "Depth of Discharge (DoD)" means the level to which a BESS is discharged relative to the maximum possible amount of energy that can be discharged by the system, typically expressed as a percentage.

(j) "Module" means the collection of Photovoltaic (PV) cells connected together.

(k) "Power Conversion System (PCS)" means an integrated system of inverters, rectifiers, controllers, and associated power electronics that convert Direct Current (DC) power from the battery to Alternating Current (AC) power for the electricity system (discharging), and vice versa (charging).

(l) "Power Plant Controller" means the equipment in a renewable energy power plant responsible for maintaining a reference active and reactive power output from the renewable energy power plant and also capable of sending & receiving signals from remote end.

(m) "State of Charge (SoC, %)" means the present level of charge of a battery expressed in percentage of its maximum capacity.

(n) "State of Health (SoH)" means the maximum level of charge of a battery expressed in percentage of its initial value at the time of its first use.

4. FLEXIBILITY REQUIREMENTS

4.1 The BESS Project may comprise multiple clusters/blocks; soft segregation of clusters for contracted capacity is permitted, provided that:
(a) the committed capacity can be dispatched and monitored independently; and
(b) separate telemetry for the committed reserve is ensured. Signal list is provided in the latter part of this document.

4.2 The BESS shall not be subject to any operational restrictions imposed by the battery manufacturer or any other OEM in the project supply chain that may lead to suboptimal utilisation of the contracted BESS capacity. In particular, there shall be no mandated "cooling-off" period or any similar constraint between charging and discharging operations. The BESS shall be capable of seamless and immediate transition between charging and discharging modes (for example, from –100 MW to +100 MW at the Point of Interconnection), subject only to grid security requirements and applicable protection limits, and without any intervening idle or restriction period.

5. FUNCTIONAL REQUIREMENTS FOR SECONDARY RESERVE ANCILLARY SERVICE (SRAS)

Automatic Generation Control (AGC) will be utilized for the deployment of reserves under SRAS.

5.1. AGC Signal List for BESS

A signal list for integrating Battery Energy Storage Systems (BESS) under Automatic Generation Control (AGC) has been prepared. This signal list includes specific considerations for the unique characteristics of BESS. These considerations include:

i. **Charging and Discharging Signals**: The signal list has been designed to manage the charging and discharging processes of the BESS, ensuring that the system operates efficiently during both modes.

ii. **State of Charge (SOC) Monitoring**: Signals have been incorporated for continuous monitoring of the State of Charge (SOC) in MWh of the BESS, which is crucial for determining the energy available for discharging and the need for charging. **SOC% is defined as the ratio of the available energy (in MWh) to the rated energy capacity (in MWh) of the BESS.**

iii. **Sign Convention Adjustments**: The sign conventions have been suitably defined to handle the dual modes of operation (charging and discharging), which distinguishes BESS from conventional power plants that typically operate in generating mode.

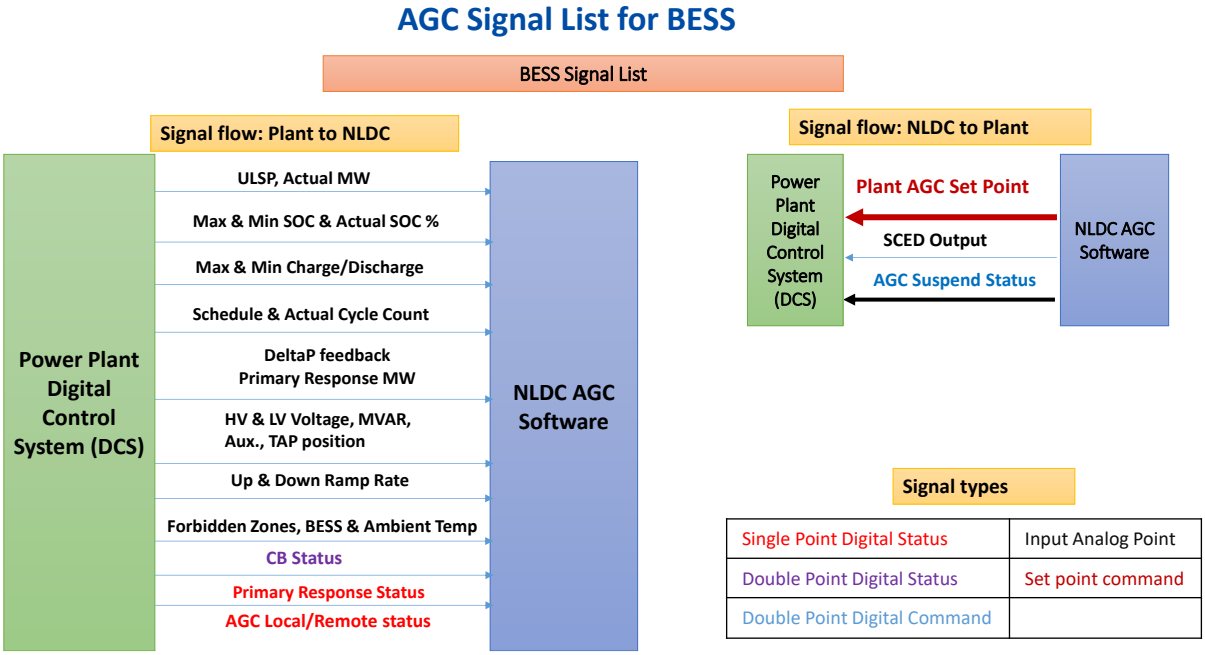


FIGURE 1 SIGNAL LIST FOR AGC OF BESS

a. Maximum MW permissible (Cap_Max)

It is the maximum MW which can be discharged (+ve value) / charged (-ve value) by the BESS at any particular point of time.

b. Minimum MW permissible (Cap_Min)

It is the minimum MW which can be discharged (+ve value) / charged (-ve value) by the BESS at any particular point of time.

c. Ramp rate up permissible

It is the maximum MW/min with which the BESS can be discharged (+ve value) by AGC at any particular point of time.

d. Ramp rate down permissible

It is the maximum MW/min with which the BESS can be charged (-ve value) by AGC at any particular point of time.

e. Actual MW

It is the actual charge/discharge MW value of the BESS.

f. ULSP

It is the scheduled value of the BESS, for fulfilling the stakeholder contracted energy/power. It is analogous to Unit Load Set-Point (ULSP) or RLDC schedule of a conventional power plant. Without Ancillary Services (SRAS and TRAS), BESS would discharge/charge this MW value. This Scheduled MW (ULSP) would be positive value while discharging, and negative value while charging.

For the committed reserve, ULSP = 0.

g. Circuit Breaker status

To understand whether the BESS is on or off. Ensuring the quality of this information is also very critical for AGC. This is a double point signal (2 - CB closed, 1 - CB open, 0 - in between).

h. Local/Remote status

The manual choice to take the BESS into local or remote is with the plant shift engineer through DCS. A suitable user interface shall be developed by the instrumentation team at every plant for taking BESS into Local/Remote. This is a single-point digital signal (0 – Local, 1- Remote).

"Remote" means unit Delta P shall be added to ULSP before processing the signal for maximum and minimum limits and further sending it to master control. Thus, if a BESS is in Remote, it is ready to accept and respond to AGC signals. "Local" means block Delta P shall not be added to ULSP. This choice can be because of onsite problems, non-readiness to accept AGC signals, prolonged communication failure, etc.

i. Minimum State of Charge SOC % permissible

It is the minimum value of SOC % up to which a BESS can be discharged. Default value would be 0%. Default Maximum SOC would be 100% (Additional signal may be configured, if needed).

j. Actual State of Charge SOC %

It is the current value of SOC % of the BESS. Beyond Maximum and Minimum SoC%, AGC software would stop sending AGC signals to BESS.

k. Scheduled Cycle count per day no.s

It is the number of round-trip cycles of BESS allowed per day. Default value would be 2-3 cycles/day.

l. Actual Cycle count per day no.s

It is the number of round-trip cycles of BESS exhausted at any point of time in the day, after 0000 hrs of that day. If the Actual Cycles count becomes equal to or greater than Scheduled Cycle count, then AGC software would stop sending AGC signals to BESS.

m. BESS forbidden zones

Information regarding any forbidden zones in which BESS should not be operated. This is analogous to the prohibited zones of Francis Hydro Turbines.

n. AGC Set Point MW from LDC to BESS

This is the signal from LDC to BESS, for the purpose of AGC control. This signal would contain the components of Scheduled MW and a correction corresponding to Area Control Error (ACE), and honours the limits mentioned above. The set point would be positive value while discharging, and negative value while charging.

The following signals would also be needed for monitoring purpose

o. Actual MVAR
p. Auxiliary Consumption MW
q. BESS Temperature
r. Ambient Temperature
s. Voltage (kV) at grid level
t. Voltage (V) at BESS LV side
u. Feedback/handshake signals
v. Primary Response MW
w. Primary Response ON/OFF status
x. Tap position
xi. State of Health (%)

5.2 Logics for handling SOC and Cycles in BESS

The below logics are provided by NLDC to be implemented at the BESS and NLDC for an effective approach to monitor and control the state of charge (SOC) and cycle count of a Battery Energy Storage System (BESS).

a. SOC Calculation

SOC(t) = SOC(t - 1) + ΔSOC(t)

Where:

SOC(t) is the State of Charge in MWh at time t.

RTE is the round trip efficiency in percentage (AC-AC)

SOC(t - 1) is the State of Charge at the previous time step (t - 1).

ΔSOC(t) is the change in State of Charge at time t.

ΔSOC(t) can be calculated by integrating the net power flow into or out of the system over a specific time interval (Δt). This formula assumes the state of health (SOH) of the BESS as 100%. In other words:

ΔSOC(t) = ∫[P_charge(t)*RTE - P_discharge(t)] dt

If instead of RTE, charging efficiency (η_c) and discharging efficiency (η_d) are separately available, then –

$$\Delta SOC(t) = \int [\eta_c \, P_charge(t) - \frac{P_discharge(t)}{\eta_d}] \, dt$$

Where $RTE = \eta_c * \eta_d$

SOC_cycle in MWh is defined as the total energy associated with fully charging and then fully discharging the BESS.

For example, for a BESS committed reserve of 250 MW / 500 MWh, the SOC_cycle for one complete cycle corresponds to the total energy associated with fully charging and then fully discharging the BESS. Since the committed reserve is 500 MWh, the energy involved in one full charge and one full discharge amounts to 500 MWh each, resulting in a SOC_cycle of 500 × 2 = 1000 MWh for a single cycle.

b. Cycle Detection Logic

Cycle: means the charging of a Battery from its Depth of Discharge (DOD) level to its peak charging level (or Rated SOC = committed reserve MWh) and again discharging to its DoD level.

Depth of Discharge (DOD): means the level to which a BESS is discharged relative to the maximum possible amount of energy that can be discharged by the system, typically expressed as a percentage.

- **Partial Cycle:** Each change in SOC, whether an increase or a decrease, results in a partial cycle. The magnitude of a partial cycle can be estimated using the formula: Partial Cycle = ΔSOC / SOC_cycle
- **Total Cycle Count:** The total cycle count of the BESS is the sum of all partial cycles accumulated over a day.

c. Operational Logic Based on SOC and Cycle Count

The following conditions are applied at the BESS based on SOC and cycle count:

Sno	**Condition**	**Max limit**	**Min limit**	**Local / Remote Status** (under normal conditions)
1	If Actual SOC% = Maximum State of Charge SOC % or 100%	Cap_Max	0	Remote
2	If Actual SOC% = Minimum State of Charge SOC % or 0%	0	Cap_Min	Remote
3	If Cycle Count > Scheduled Cycle Count or 2	0	0	Local

- **Condition 1**: If the SOC% reaches its maximum (100%), the system will set Cap_Max and disable further charging (Cap_Min = 0). The control system can still remain under remote status. The BESS can respond only to discharging commands from AGC software of NLDC.
- **Condition 2**: If the SOC% reaches its minimum (0%), the system will set Cap_Min and disable discharging (Cap_Max = 0). The control system can still remain in remote status.
- **Condition 3**: If the cycle count exceeds the scheduled number of cycles (say reaches a threshold of 2), the system switches to local status. The BESS needs to only monitor and need not respond to the signals from AGC software of NLDC.

The above ensures the battery is efficiently managed based on its charge and discharge cycles while respecting predefined thresholds for optimal performance.

6. PERFORMANCE STANDARDS AND INDICES

6.1 AVAILABILITY

6.1.1 The availability of the committed reserve shall be computed on a weekly basis.

6.1.2 The target Availability shall not be less than 95%.

6.1.3 Availability for a given period shall be calculated as:

Availability (%) = ((Duration of Committed Reserves – Forced Outage Hours – Hours of Telemetry/Communication Non-Availability) ÷ Duration of Committed Reserves) × 100

6.2 SRAS PERFORMANCE INDEX (PI_S)

6.2.1 The SRAS Performance Index shall be calculated daily as per the methodology notified in the CERC (Ancillary Services) Regulations, 2022 and the NLDC Detailed Procedure for SRAS as amended from time to time. The publication follows a weekly cycle by the RPCs.

6.2.2 A daily PI_S of **95% or above** in the SRAS-2 format (weekly) shall be considered as compliant performance.

6.3 ROUND TRIP EFFICIENCY (RTE)

6.3.1 The weekly RTE at Point of Interconnection (PoI) shall be calculated as:

RTE (%) = (Total Energy Discharged (MWh) ÷ Total Energy Charged (MWh)) × 100

considering only the energy associated with Ancillary Services operation.

6.3.2 The BESS shall maintain a **weekly RTE of not less than 85%**.

6.4 STATE OF CHARGE (SOC) AND CYCLE MANAGEMENT

6.4.1 Automatic Generation Control (AGC) shall charge or discharge the BESS, as required by system conditions, based on the custom participation factor (as per the methodology notified in the CERC (Ancillary Services) Regulations, 2022 and the NLDC Detailed Procedure for SRAS) assigned through the AGC software. Accordingly, the State of Charge (SOC) of the BESS may vary within the range of 0% (or minimum) to 100% (or maximum), utilizing upward and downward reserves for SRAS.

6.4.2 In the event the BESS is fully discharged, the NLDC may, if required to meet system exigencies, charge the BESS under SRAS through a manual change in set point / TRAS. Similarly, when the BESS is fully charged, the NLDC may discharge the BESS under SRAS through a manual change in set point / TRAS.

6.4.3 The AGC may utilize the BESS for up to two cycles per day, subject to system requirements. Anticipatory management of BESS charging and discharging, to conserve cycles for situations when required by the system, may also be carried out by the NLDC through appropriate changes in software inputs.

6.4.4 The Energy Management System (EMS) at the BESS shall enforce SOC limits and provide appropriate alarms and curtailment logic to prevent SOC excursions that may compromise SRAS availability.

7. METERING, TELEMETRY AND COMMUNICATION

7.1 The necessary signals as desired by the system operator shall be telemetered in the required protocol such as IEC 60870-5-104.

7.2 The committed reserve shall have clearly segregated SCADA telemetry to enable accounting and monitoring for SRAS. The BESS Project may comprise multiple clusters/blocks. It would be desirable to have separate metering for the committed reserve.

Soft segregation of clusters for committed reserve is permitted, provided that:
(a) the committed reserve can be dispatched and monitored independently; and
(b) separate telemetry and accounting for the committed reserve is ensured.

7.3 The BESS controllers, Battery Management System (BMS) and Energy Management System (EMS) shall support standard communication protocols such as IEC 60870-5-104 and integration with NLDC/RLDC and CTUIL systems for the purpose of Automatic Generation Control (AGC).

7.4 The BESS shall telemeter all the required signals for AGC with high accuracy and precision.

7.5 BESS Operator shall record high-resolution electrical and control data and preserve the same for analysis and SRAS accounting at least 90 days.

7.6 Any changes in firmware, control logics or settings likely to affect grid support functions shall be notified in advance and may require repeat tests of affected functionalities.

8. COMMERCIAL SETTLEMENT

The settlement for the committed reserves shall be on a weekly basis through the Deviation and Ancillary Services Pool Account (DAS Pool).

8.1 FIXED CHARGES FOR COMMIITTED RESERVES

8.1.1 Fixed monthly charge (₹/MW/month) for the committed reserves shall be converted to Fixed weekly charge (₹/MW/week).

8.1.2 Full fixed weekly charge shall be recovered by the BESS when all of the following conditions are satisfied.
(a) Weekly Availability ≥ 95%;
(b) Weekly SRAS Performance Index (PI_S) ≥ 95%; and
(c) Weekly RTE ≥ 85%.

8.2 PENALTIES FOR AVAILABILITY SHORTFALL

8.2.1 In case of yearly Availability below 95%, the capacity charges for that contract year may be reduced as under:
(a) 90% to <95% – 5% reduction in annual capacity charges;
(b) 85% to <90% – 10% reduction;
(c) <85% – 20% reduction, and classification as under-performing.

8.2.2 If the Availability is less than 85% for two consecutive weeks, the Procurer/System Operator may, after due notice, de-rate the contracted capacity or terminate the contract in accordance with the agreement.

8.3 PENALTIES FOR SRAS PERFORMANCE DEVIATION

8.3.1 Where the daily PI_S as per the SRAS-2 format falls below 95%, capacity charges for that week may be reduced as under:
(a) 90% to <95% – 5% reduction;
(b) 85% to <90% – 10% reduction;
(c) <85% – 20% reduction and requirement of a corrective action plan from the BESS Owner.

8.4 PENALTIES FOR RTE SHORTFALL

8.4.1 Where the weekly RTE falls below 85%, the capacity charges may be reduced as under:
(a) 80% to <85% – 5% reduction;
(b) 70% to <80% – 10% reduction;
(c) <70% – 20% reduction and investigation into equipment or operational deficiencies.

8.5 ENERGY CHARGES FOR COMMIITTED RESERVES

8.5.1 Charging and discharging of BESS to be done by NLDC under SRAS / TRAS. No separate energy payment shall be made for committed reserves.

8.6 INCENTIVE FOR COMMIITTED RESERVES

8.6.1 No separate incentive payment shall be made for committed reserves.

9. REVIEW AND AMENDMENTS

10.1 Grid-India, in consultation with CEA, CERC and other stakeholders, may review these provisions periodically based on operational experience, technological advancements and system requirements.

10.2 Any amendment shall be notified by the CERC and shall thereafter form part of this Procedure.

ANNEXURE-II

सत्यमेव जयते

No. 11/7/2026-Th.II
Government of India
Ministry of Power

Shram Shakti Bhawan, Rafi Marg,
New Delhi, dated: 10th February,2026

To,

CEO
NTPC Vidyut Vyapar Nigam Ltd. (NVVN)
Scope Complex, Lodhi Road
New Delhi.

Subject:- Salient features of the proposed scheme for peak power procurement from generators/ energy storage providers selected through competitive bidding for market-based power sale and TRAS/ SCUC during the period from 1st Apr'26 to 30th Jun'26 -reg.

Madam,

I am directed to refer to the subject mentioned above and to say that in order to meet the projected unprecedented high demand for power during upcoming crunch periods **from 01st April,2026 to 30th June'26**, a mechanism for peak power procurement from generators/ energy storage providers selected through competitive bidding for market-based power sale and TRAS/ SCUC has been finalized and same is enclosed as **Annexure.**

2. NVVN is requested to expedite preparation of competitive bidding document and to initiate the bidding for peak power procurement of power for the upcoming crunch period to support the peak demand, as per the mechanism.

3. Further, it is to inform that Steering Committee constituted by this Ministry vide OM dated 09.03.2023 shall endeavor to resolve the issues associated with the bidding process for the above Scheme and the payment settlement mechanism.

4. This issues with the approval of Hon'ble Minister of Power & Housing & Urban Affairs.

Yours Sincerely,

Encl: As above

Acharya 10/02/26

(Chittaranjan Acharya)
Under Secretary (Thermal)
Tele: 2371-9710

Copy to: -

1. Secretary, Ministry of Petroleum & Natural Gas
2. Secretary, Ministry of New & Renewable Energy.
3. Chairperson, CEA
4. CMD NTPC
5. CMD, Grid India.

C Acharya 10/02/2026

(Chittaranjan Acharya)
Under Secretary (Thermal)
Tele: 2371-9710

Annexure

Salient features of the proposed scheme for peak power procurement from generators/ energy storage providers selected through competitive bidding for market-based power sale and TRAS/ SCUC during the period from 1st Apr'26 to 30th Jun'26 -reg

1. Brief Overview of the Scheme

(i) As per Grid India analysis, it is expected that stressed supply situation and shortage in reserves may occur during non-solar hours during crunch period (April – June 2026).

(ii) To supplement the available generating capacity during the upcoming crunch period, it is proposed that NVVN may carry out procurement of up to 12000 MWh (2000 MW for 6 hours) per day of electricity from generation/ storage resources during the crunch period April-June 2026. The contracted capacity will be at the disposal of a Nodal Agency. Generators/ energy storage providers commissioned before the start of contract period shall be eligible to participate in the scheme. As in earlier such schemes, NVVN may be nominated as Nodal Agency.

(iii) Minimum Guaranteed Off-take (MGO) for generators/ energy storage providers would be calculated as per requirement specified by NLDC based on estimated crunch days and 50% contracted capacity. MGO for each generators/ energy storage providers would be allocated in proportion of contracted capacity to the total bid capacity. MGO will be applicable on energy basis only.

(iv) The cumulative generation days as given by NLDC on provisional basis for the crunch period shall be 50 days. However, the month-wise generation days for power plant for crunch period shall be provided by NLDC based on requirement and with provision for extension/revision during implementation.

(v) The contracted capacity shall be able to be despatched on stressed days during non-solar peak hours (18:00 to 04:00 hrs), for minimum 2 hours and maximum 6 hours.The generation profile of identified procured resources would be minimum 50% of contracted capacity for the generators/ energy storage providers selected on D-1 days for the duration quoted in the bid and may be scheduled upto 100% of contracted capacity during Non-solar peak hours as per grid requirement. E.g. for12000MWh of contracted Energy, Minimum Guaranteed Off-take (MGO) per day shall be 6 MU per day and shall be 300 MU for the crunch period of 50 days (considering 6 hours per day). If lesser quantity is contracted, the MGO will reduce proportionately.

(vi) Nodal Agency in consultation with NLDC shall communicate to the **procured resources** at least fourteen (14) days in advance about the approximate number of crunch days based on all India demand forecast and generation availability in the following week of operation on which the generation is likely to be required in the grid. Considering weather uncertainty, approximate no. of days would be reviewed again in just previous week and any changes would be intimated to all generators/storage resource by Friday of

previous week. The **procured resources** shall accordingly arrange the peak power supply during the said week (Monday to Sunday) as per the schedule communicated by NLDC on D-1 day. In case of energy storage services, arrangement of charging power shall be in the scope of respective energy storage services for supply of power during peak hours.

(vii) The modalities for utilization of the contracted capacity during the crunch period shall be as under:

(a) Out of the contracted capacity, NVVN would endeavour to sell the power in any segment of the power exchange immediately after signing of contract.

(b) The selected generators/ energy storage providers may also seek avenues for sale of power for part or full crunch period and such sale shall be executed through the Nodal Agency. This will ensure that Nodal Agency is fully aware of the utilization of the capacity and there are no contractual complications at a later stage.

(c) The Nodal Agency in consultation with NLDC shall communicate to the Generators/ storage service providers at least fourteen (14) days in advance about the approximate number of crunch days in the following week of operation on which the generation is likely to be required in the grid.

(d) The generators/ energy storage providers shall arrange for the fuel arrangements/ charging power requirement and other necessary arrangements based on generation profile as emerging from above.

(e) During the operating week, NLDC will give confirmation for generation/ supply of energy to one or more generators/ energy storage providers at 0500 hours on D-1 day depending on the available MGO quantum with the generators/ energy storage providers and requirement of grid. Post this, NVVN will offer the available quantum in power exchange.

(f) If NLDC has given confirmation for part capacity on D-1 basis to a generator/ energy storage provider, the Nodal Agency may sell full/part of the remaining contracted capacity of that generator/ energy storage provider during peak hours in the market at a rate which shall at least be equal to the discovered rate for that generator/ energy storage provider.

(g) Any left-over contracted quantum from generator/ energy storage provider, which was given confirmation on D-1 day, would be scheduled by NLDC on D- day for grid support/requirement under ancillary services as per IEGC/ancillary services regulation.

(viii) Any energy sold out of contracted capacity shall be counted in the MGO for that generators/ energy storage providers.

(ix) In case of energy requirement beyond MGO quantum, Nodal Agency may schedule such energy up to the Contracted Capacity to generators/ energy storage providers to supply such additional energy.

(x) The contract period, may be extended upto 31st July 2026, with the consent of the selected generators/energy storage providers as per same terms and conditions of the supply.

(xi) The selected bidders will have to arrange fuel/ charging power requirement and other arrangements on their own.

(xii) The bidder shall provide the technical details such as maximum, minimum duration for which bidder can supply the power on continuous basis along with technical constraint.

(xiii) The supplier may be required to start/stop the plant daily in accordance with the power requirement and cleared schedule.

(xiv) DSM Charges shall be in the scope of generators/ energy storage providers as per the applicable DSM Regulations.

(xv) The generators/ energy storage providers connected to inter-state or intra-state transmission system participating in the bid shall have all necessary infrastructure in place and capability for scheduling, metering, accounting and settlement on a 15-minute time- block wise basis as specified in the Indian Electricity Grid Code. The generators/ energy storage providers shall provide necessary undertaking that sufficient transmission capability is available for injection of power during peak hours.

(xvi) No planned maintenance shall be allowed during the identified crunch period.

(xvii) The schedule which is not able to be fulfilled due to fuel supply constraint or Transmission/Grid constraint, subject to documentary evidence, shall be treated as Force Majeure without any liability on either side, and deemed to be fulfilled with regard to Minimum Guaranteed Offtake (MGO) obligation. Any consequent DSM liability due to such constraint will be to the account of generators/ energy storage providers.

2. Commercial Arrangements:

(i) The tariff payable will be on Rs/kWh basis fixed for the entire crunch period.

(ii) The NVVN trading margin may be fixed at **6 Paise/kWh** payable by the generator/ energy storage provider under this scheme for the energy scheduled through various market segments including under shortfall provisions of TRAS/ SCUC.

(iii) The bidding in power exchange shall be considering discovered tariff. In case of excess amount received from power exchange sale after accounting for NVVN trading margin, 90% of the same shall be deposited in the DSM and Ancillary pool account after the end of the crunch period. However, 10% of such excess amount shall be paid to the generators/ energy storage providers as incentive.

(iv) For generation beyond MGO, discovered tariff during competitive bidding conducted by Nodal Agency shall be payable.

(v) Any shortfall in the daily availability leading to inability of the generators/ energy storage providers to schedule the generation as per profile advised by National Load Dispatch Centre (Grid India), will attract penalty at the rate of 10% of discovered tariff.

(vi) NVVN shall declare tariff for TRAS/ SCUC with adjustment for power exchange charges, such that generators/ energy storage providers recover only the total tariff (discovered tariff – power exchange charges). Despatch of selected generators/ energy storage providers under TRAS/ SCUC shall be as per merit order amongst the selected generator(s)/ energy storage provider(s) based on discovered tariff.

(vii) The payment to the generators/ energy storage providers for power traded through exchange shall be made by NVVN on D+2 basis. Payment to the generators/ energy storage providers for power scheduled through TRAS/ SCUC shall be as per CERC regulations/procedures.

(viii) The Nodal Agency shall provide payment security to the generators/ energy storage providers through revolving letter of credit equivalent to one day of amount payable to the Seller (Discovered Tariff) commensurate to Minimum Guaranteed offtake with respect to their contracted capacity for one day. This payment security shall be applicable only for Bilateral/Market Transactions and not under TRAS/ SCUC.

(ix) 5% of total payment corresponding to minimum Guaranteed offtake shall be kept against the reconciliation amount and shall be released to the generator after the reconciliation. The amount against the same shall be recovered from running bill @5% per bill. LPS shall not be applicable for the above amount.

(x) Any amount received as penalty/ EMD/CPG forfeiture etc. and any excess amount collected above discovered rate shall be adjusted first against MGO financial obligations and thereafter deposited in concerned regional deviation and ancillary pool.

3. Bidding Process:

(i) The Nodal Agency would call for bids based on total tariff for peak power supply in Rs/kWh. The bidder also needs to specify the duration for which it wants to supply (**minimum two hours per day, and maximum six hours per day**) The quoted tariff shall cover all inputs costs including but not limited to such as fixed costs and other associated components, O&M, fuel, charging energy, RtE Impact, transmission charges and losses applicable during charging (in case of storage), NVVN trading margin, Power Exchange Charges, state transmission charges and transmission losses (if any), SLDC charges etc., as applicable. Discovered tariff after eRA shall remain unchanged throughout the duration of the crunch period.

(ii) Nodal agency will give 12 days' time for submission of bid after issuance of RfS. Pre-Bid meeting will be done 7 days after issuance of RfS. If any change in RfS is required after pre-bid meeting, additional 3 days' time will be given for submission of bids after changes in RfS are conveyed to potential bidders on bidding portal.

(iii) The Nodal Agency shall specify **a minimum capacity of 25 MW** to be offered by a bidder.

(iv) The bidding will be conducted through the e-bidding process with bid submission through a suitable e-bidding platform followed by e-Reverse Auction (e-RA). This shall be followed by bucket filling.

(v) The bid evaluation parameter will be tariff in Rs/kWh for peak power supply.

(vi) The bidder may provide minimum contracted capacity to be considered for selection in the bidding process

(vii) Bucket Filling: e-Reverse Auction process shall be conducted for all bidders bidding for Crunch Period. While conducting e-Reverse auction, the H1 bidder shall be eliminated, if such elimination does not lead to availability of power below **12,000 MWhr per day**.

(a) The Nodal Agency shall list out all the bidders in the increasing order of bid evaluation parameter (Tariff in Rs/kWh).

(b) Only those bidders will be eligible for bucket filling for whom bid evaluation parameter is less than or equal to **125%** of the bidding parameter for L1.

(c) Bucket will be filled by sequentially selecting bidders starting from L1 with lowest value of bid evaluation parameter shall be sequentially selected so as to reach total contracted capacity of **12,000 MWhr per day**.

(d) While filing bucket, in case of tie in the value of bid evaluation parameter, the bidder with higher capacity offered shall be given preference.

4. Commencement of Supply and other issues

(i) NVVN shall ensure timeline of bidding process such that supply of power from selected generators/ energy storage providers shall commence during crunch period in not less than 30 days from the date of issue of Letter of Award (LoA).

(ii) All the prospective Bidders will inform the PPA beneficiaries of participation in the scheme, shall submit NOC from PPA holders for the tied capacity, and shall not charge fixed charges from the PPA holders for the days of operation under the scheme. In case bidder proposes to bring untied capacity for supply under the scheme he/she shall submit declaration.

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