TAMIL NADU POWER DISTRIBUTION CORPORATION LTD

From

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To
The Secretary,
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Lr. No. CFC/RC/SE/CERC/EE1/AEE4/ F. IEGC Reg./D. 276/26 dt: 02.11.2026

Sir,

Sub: TNPDCL- Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026 - Comments of TNPDCL - Submission– Regarding.

Ref: Public Notice No. L-1/265/2022/CERC dated 21.09.2026 & 22.10.2026.

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Adverting to the above reference, the comments of TNPDCL on the Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026 are enclosed as Annexure, for consideration of the Hon'ble Commission.

Yours faithfully,

R Krishnaswami
02.11.2026
Chief Financial Controller
Regulatory Cell

Encl.: As above

Annexure

COMMENTS AND SUGGESTIONS OF TNPDCL ON THE DRAFT CERC (IEGC) SECOND AMENDMENT) REGULATIONS, 2026, DATED 21.09.2026

I. General observations of TNPDCL

Tamil Nadu Power Distribution Corporation Limited (TNPDCL) has analyzed the Draft CERC (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026 and its Explanatory Memorandum. The amendments have been assessed not only for operational flexibility to generating stations, energy storage systems and load despatch centres, but also for their commercial and operational consequences for distribution licensees responsible for meeting consumer demand at reasonable cost.

TNPDCL appreciates efforts to improve grid security, renewable integration, storage operation and congestion management. Nevertheless, grid-security measures must be transparent and proportionate; PPA rights, scheduling flexibility and beneficiaries' remedies must be preserved; and system inadequacy, generator-side constraints and centrally directed actions must not result in unverified additional charges to DISCOMs. Adequate notice, published technical methodologies, auditable accounts and safeguards against duplicate recovery are essential.

II. Regulation-wise comments and objections

1. Regulation 3 – Congestion Charge and Default Trigger Date

The proposed congestion-charge definition should distinguish congestion of a specific transmission element from breach of the Available Transfer Capability (ATC) or Total Transfer Capability (TTC) of a defined corridor. An overloaded line does not by itself establish exceedance of corridor TTC. Liability should arise only where an entity's deviation is demonstrably attributable to and materially aggravates the constraint.

The proposed default-trigger framework should distinguish admitted dues from genuine disputes involving RPC accounts, metering, revisions or payment-security

requirements. Restricting access without verification and a fair opportunity to resolve the issue could adversely affect essential consumer supply. TNPDCL requests objective causation criteria, advance notice, correction and dispute procedures, and protection against coercive measures for bona fide disputed amounts.

2. Regulation 19(3) – Extension of interchange of power before COD

Extensions of up to three months in all for REGS and ESS should remain operational permissions only. The regulation should state expressly that they do not extend the SCOD, condone delay or waive liquidated damages or other PPA remedies, since delayed capacity forces DISCOMs to buy replacement power at higher cost. Beneficiaries should receive reasons, revised milestones and advance notice of every extension.

3. Regulation 21(1) – Notice for trial run

TNPDCL submits that the proposed reduction of the mandatory notice period for trial runs from seven days to three days requires reconsideration. The existing seven-day notice enables beneficiaries to nominate representatives, coordinate with the concerned agencies and verify the technical and contractual performance of generating stations before declaration of commercial operation. This is particularly important for large generating stations, pumped storage plants and energy storage systems, where successful trial operation may have significant implications for COD, commencement of contractual supply and associated financial obligations. Reduction of the notice period solely to facilitate early commissioning may restrict the beneficiaries' opportunity to witness and verify the performance tests and could give rise to subsequent contractual disputes.

TNPDCL therefore requests that the existing seven-day notice period be retained as the normal requirement, with provision for reducing it to three days wherever the affected beneficiaries expressly consent. This would facilitate early commissioning without compromising the technical verification and contractual rights of beneficiaries.

4. Regulation 22(3)(a), (c) and (e) – Instalment-wise trial runs

Comments of TNPDCL

4.1 TNPDCL supports instalment-wise trial runs for Renewable Energy Generating Stations and standalone ESS. They allow phased commissioning and let completed capacity be put to use sooner.

4.2 For projects of 250 MW or more, the draft places no limit on the number of instalments. This flexibility should not become a way to extend commissioning schedules or to weaken the performance obligations in the PPA. TNPDCL submits that:

- (a) the instalment-wise trial run should not change the Scheduled Commissioning Date, the liquidated damages or any other contractual consequence of delay under the PPA;
- (b) COD and the related tariff liability should apply only to the capacity that has actually completed its trial run;
- (c) the developer should give the RLDC and the beneficiaries its full instalment plan (capacity and expected date of each instalment) before the first instalment. Any change to that plan should be notified in advance.

4.3 Trial-run requirements for BESS: the existing Regulation 22(3)(e) defines a successful trial run as one charge-discharge cycle "as per the design capabilities". TNPDCL submits that this cycle should demonstrate:

- (a) rated power capacity (MW);
- (b) usable energy capacity (MWh);
- (c) the contracted discharge duration (for example, 2 or 4 hours);
- (d) round-trip efficiency, where it is specified in the PPA or the bid documents.

Where the trial run is done in instalments, each instalment should demonstrate its proportionate energy capacity (MWh) along with its power capacity (MW). Otherwise, power capacity could be declared commercially operational before the matching energy capacity has been demonstrated. Beneficiaries procure BESS mainly to meet peak-hour demand, so a BESS that cannot sustain its rated output for the contracted duration does not serve its purpose.

4.4 Clarification needed on instalment limits. For ESS between 50 MW and 250 MW, the draft (Para 5(6)) allows the balance capacity in a maximum of **three** instalments. For solar and wind projects of the same size, the limit is **four** instalments. The Explanatory Memorandum (Para 6.5) says the ESS provisions follow those for solar generating stations, and Para 6.6 refers to five instalments in all. The Commission may clarify which limit is intended for ESS and align the draft with the Explanatory Memorandum.

Suggestion

TNPDCL requests that:

- (i) instalment-wise trial runs be permitted on the condition that they do not alter the commissioning timelines or contractual obligations under the PPA, by adding a proviso to that effect in sub-clauses (a), (c) and (e);
- (ii) the BESS trial-run requirement in sub-clause (e) expressly cover rated MW, usable MWh and the contracted discharge duration, for each instalment as well as for the full capacity;
- (iii) the instalment limit for ESS between 50 MW and 250 MW be clarified.

Suggested proviso for sub-clauses (a), (c) and (e):

"Provided also that the performance of the trial run in instalments shall not alter the scheduled commissioning date or any other obligation of the generating station or ESS under the PPA, and the COD shall be declared only for the capacity for which the trial run has been successfully completed."

Suggested addition to sub-clause (e):

"…which shall demonstrate the rated power capacity (MW), the usable energy capacity (MWh) and the contracted discharge duration, for each instalment and for the total installed capacity."

5. Regulation 22(3)(f) – Pumped Storage Plant trial operation

TNPDCL requests that:

(i) the trial-run requirement for PSP specify rated output and input in both modes for the contracted duration, with plant-level demonstration of usable storage energy and cycle efficiency;

(ii) proviso (iv) be harmonised with the existing first proviso, and the post-COD demonstration be made time-bound with deemed de-rating if it is not done;

(iii) de-rating be accompanied by reconciliation and refund of excess payments from the original COD;

(iv) a proviso be added clarifying that COD under the Grid Code does not override the performance and acceptance requirements of the PPA.

Suggested proviso for sub-clause (f):

"Provided also that where the capacity of a unit of a pumped storage plant is de-rated after COD, the capacity charges and other payments for the de-rated capacity shall be reconciled from the date of COD, and any excess amount paid by the beneficiaries shall be refunded with carrying cost:

Provided also that declaration of COD under these Regulations shall be without prejudice to the performance tests and acceptance requirements stipulated in the Power Purchase Agreement or the Energy Storage Agreement."

6. Regulation 22(3)(j) – Capacity demonstration delayed by transmission constraints

TNPDCL requests that sub-clause (j) be recast as follows:

"(j) Where it is not possible to demonstrate the rated capacity of a plant within one year from the date of COD due to non-availability or inadequacy of the inter-State or intra-State transmission system required for evacuation of power from the plant, as certified jointly by the concerned transmission licensee and the concerned RLDC, such plant may demonstrate the balance rated capacity within one year from the date of effectiveness of the GNA or one year from the date of COD, whichever is later:

Provided that the relaxation under this sub-clause shall not be available where the inability to demonstrate the rated capacity is attributable to incomplete works, equipment deficiencies, or delay or inadequacy in the dedicated transmission system or other evacuation infrastructure that is the responsibility of the generating station:

Provided further that the plant shall demonstrate its capacity to the extent of the evacuation capacity available, and payments and performance assessment during the extended period shall be limited to the capacity so demonstrated:

Provided also that where the balance rated capacity is not demonstrated within the period specified in this sub-clause, the capacity shall be de-rated in terms of sub-clause (h) of this clause:

Provided also that nothing in this sub-clause shall affect the commissioning obligations, performance guarantees and other obligations of the generating station, or the rights and remedies of the beneficiaries, under the Power Purchase Agreement."

7. Regulations 24, 26 and 27 – ESS/PSP integration and COD

Proposed amendment

The draft requires pumped storage plants above 25 MW, and other ESS of 25 MW and above, to enable automatic operation from the load despatch centre (Regulation 24). It extends the COD declaration requirements to pumped storage plants (Regulation 26). It allows the COD of a pumped storage plant to be declared unit by unit (new Regulation 27(1)(b-i)). For RE stations and ESS, COD is to be declared after a successful trial run, while supply under the contract begins only once the contractual conditions are met (Regulation 27(1)(e)(i)).

Comments of TNPDCL

7.1 TNPDCL has no objection to the arrangements for automatic operation and COD declaration of ESS and pumped storage plants. However, automatic operation should be enabled before COD is declared, since a unit that cannot respond to dispatch does not provide the flexibility for which storage is procured.

7.2 A pumped storage plant delivers an integrated service that depends on shared works: the reservoirs, the water conductor system, pumping capability and the evacuation facilities. A unit's successful trial run shows only that the unit is ready. It does not show that the plant can deliver the contracted peak output for the contracted duration, or absorb energy in pumping mode. Unit-wise COD should therefore not be treated as completion of the contracted storage service.

7.3 COD under the Grid Code and COD under the contract should remain separate. The draft accepts this for RE stations and ESS in Regulation 27(1)(e)(i), but not for pumped storage plants in sub-clause (b-i). COD under the Grid Code should not, by itself, make the beneficiaries liable for capacity charges or any other payment. Capacity charges should

begin only when the PPA conditions are met, including demonstration of peak output, duration and pumping capability.

7.4 The draft does not say how power is to be treated in the gap between COD under the Grid Code and fulfilment of the contract conditions. During this period, beneficiaries should not be obliged to schedule or pay for such power, except with their consent and on mutually agreed terms.

Suggestion

TNPDCL requests that the following proviso be added to sub-clause (b-i) of Regulation 27(1), with a similar clarification in sub-clause (e)(i):

"Provided that where the contract requires conditions other than those in these regulations as a prerequisite for commercial operation, including demonstration of the contracted peak output, discharge duration and pumping capability, the Pumped Storage Plant shall meet those conditions before supplying power under the contract:

Provided further that declaration of commercial operation of a unit or of the Plant under these regulations shall not, by itself, entitle the Plant to capacity charges or any other payment under the contract."

8. New Regulation 25A – Scheduling of infirm power

8.1 TNPDCL supports offering power produced before COD first to the contracted buyers. However, the provision should not become a way to delay COD or to sell contracted capacity elsewhere.

8.2 Once the trial run is complete, COD should follow promptly. If no time limit is set, a generator could keep selling infirm power at market prices and put off its PPA obligations. Scheduling under 25A should therefore be allowed only for a short, defined period.

8.3 Where power is contracted through an REIA or intermediary procurer, the notice period should run from the date the distribution licensee receives the offer. Silence by the REIA should not count as refusal by the distribution licensee.

8.4 The tariff for such power should not exceed the PPA tariff.

8.5 Sale to third parties should not extend the scheduled commissioning date, or affect liquidated damages or the buyers' rights under the PPA.

Suggested provisos to clause (3) of Regulation 25A:

"Provided that the tariff for such power shall not exceed the tariff under the contract:

Provided further that where the contract is through an REIA or intermediary procurer, the notice period shall be reckoned from the date of receipt of the offer by the end procurer:

Provided also that sale of such power to a third party shall not affect the scheduled commissioning date or any other obligation of the generating station or ESS under the contract."

9. Regulation 27(1)(e) – Regulatory COD and PPA conditions

9.1 TNPDCL supports ending indefinite infirm injection. However, the amendment creates a gap between COD under the Grid Code and COD under the PPA, and the draft does not say what happens during that gap.

9.2 COD under the Grid Code should not make the procurer liable for tariff, capacity charges or any other payment. These should start only from COD under the PPA. The scheduled commissioning date, liquidated damages and performance requirements under the PPA should not be affected.

9.3 Power generated during the gap should first be offered to the contracted procurer at a tariff not exceeding the PPA tariff. Otherwise, the station may sell at market prices and delay meeting the PPA conditions.

Suggested proviso to Regulation 27(1)(e)(i):

"Provided further that the declaration of commercial operation for the purpose of these regulations shall not, by itself, entitle the generating station or ESS to tariff, capacity charges or any other payment under the contract, which shall commence only upon fulfilment of the conditions specified in the contract:

Provided also that power generated before fulfilment of such conditions shall first be offered to the buyer(s) under the contract at a tariff not exceeding the tariff under such contract."

10. Regulation 30 – Frequency response, reserve estimation and bulk consumers

Regulation 30(11)(k) – Methodology for Estimation of Secondary and Tertiary Reserves

TNPDCL welcomes the proposal to provide flexibility in the methodology for estimation of secondary and tertiary reserves, including adoption of a percentile other than the existing 99th percentile. However, the proposed amendment does not specify the technical criteria or safeguards governing selection of the appropriate percentile.

Since reserve obligations have direct financial implications for distribution licensees and ultimately electricity consumers, any revision in the estimation methodology should be supported by transparent studies of historical Area Control Error, demand and renewable energy forecast errors, seasonal variations and credible contingencies. NLDC should publish the State-wise reserve requirements, technical validation results and comparative financial implications under the existing and proposed methodologies before implementation.

Further, reserve obligations should be determined after duly recognising the reserve capacity already maintained by States through their contracted generating stations, BESS, Pumped Storage Plants and other eligible resources, including capacity earmarked for SRAS/TRAS and approved ancillary-service arrangements, subject to verification of technical capability and actual availability.

TNPDCL submits that the same reserve capacity should not be counted more than once, nor should additional procurement costs be imposed for reserve capacity already maintained and funded by the distribution licensees. Only the verified net shortfall in the State's reserve obligation should be considered for allocation of additional reserve procurement costs, subject to the applicable regulatory framework.

TNPDCL also requests that the percentile adopted for reserve estimation be periodically reviewed based on actual system performance, rather than through an automatic transition to a higher percentile, and that the benefit of regional diversity be appropriately reflected in State-wise reserve allocation.

Accordingly, TNPDCL requests the Hon'ble Commission to incorporate suitable provisions in Regulation 30(11)(k) ensuring evidence-based reserve estimation, transparency in State-wise financial implications, recognition of eligible contracted reserve capacity and prevention of duplication in reserve procurement and cost recovery.

11. New Regulation 30A – Congestion Charge

General concerns

- **Double penalty:** the same deviation is already penalised under the CERC (Deviation Settlement Mechanism and Related Matters) Regulations, 2024; an additional, uncapped congestion charge penalises it twice.
- **Deviations largely outside the Discom's control:** they arise from wind and solar variation, weather-driven demand and generator outages, which cannot be corrected in real time except by shedding load.
- **Congestion blocks the Discom's own purchases:** when the market splits, the Discom's buy bids remain uncleared, and the shortfall appears as over-drawal that would then attract the congestion charge.
- **Transmission shortfall:** congestion is essentially a shortage of transmission capacity; its cost should not be shifted to Discoms and, through tariffs, to consumers.

Regulation 30A(1): Applicability

- **30A(1)(a):Observation:** Every deviation is treated as causing congestion, with no threshold and no exemptions.

  Suggestions:

  - Charge only deviation beyond the DSM volume limits, in the direction that worsens congestion, in proportion to each entity's contribution to the corridor flow.

- Exempt deviations caused by uncleared market bids, outages of contracted generators and RLDC/SLDC instructions.

- **30A(1)(b): Observation: E**ntities in a wheeling area are charged even when their deviation relieves congestion.
- **Suggestions:**
  - Delete the words "irrespective of the direction or nature of the deviation".
  - Define the wheeling area and declare it in the notice.
- **30A(1)(c):** the charge is levied on top of DSM charges.
  - Specify a combined cap on DSM and congestion charges per time block.

Regulation 30A(2) to 30A(4): Rate and notices

- **30A(2): Observation:** the rate is left entirely to a future order.
- **Suggestions:**
  - State the pricing principle and a ceiling in the regulation.
  - Fix the rate only after stakeholder consultation.
- **30A(3): Observation:** The charge applies on the opinion of the RLDC, with only two time blocks (30 minutes) of notice.
- **Suggestions:**
  - Trigger on SCADA-measured flow exceeding the declared TTC.
  - Increase notice to four time blocks; name the entities and the correction required of each.
  - No charge where a transmission outage has reduced the TTC.
- **30A(4): Observation:** withdrawal is optional and delayed by a further time block.
- **Suggestions:**
  - Replace "may" with "shall".
  - Withdraw the charge from the next time block.

Regulation 30A(5) to 30A(8): Settlement and procedure

- **30A(5): Observation:** The weekly statement has no supporting data.
- **Suggestions:**
    - Provide block-wise supporting data.
    - Allow seven days for entities to raise discrepancies.
- **30A(6): Observation:** payment within 10 days, with interest at 0.04% per day (about 14.6% a year).
- **Suggestions:**
    - Align payment with the DSM timeline and allow netting.
    - Apply interest as per the LPS Rules, 2022.
    - No interest on disputed amounts until they are decided.
- **30A(7)): Observation:** No consequence for late release; use of any surplus is unclear.
- **Suggestions:**
    - Provide interest on late release.
    - Use any surplus to reduce the transmission charges of DICs.
- **30A(8)): Observation:** key methodology is left to a procedure.
- **Suggestions:**
    - Set out the core methodology in the regulation itself.
    - Publish the draft procedure for comments.
    - Run a six-month trial with shadow settlement before the actual levy.
- TNPDCL requests the Hon'ble Commission to modify Regulation 30A as suggested above and to bring the congestion charge into force only after the detailed procedure is approved and a six-month trial period is completed.

12. Regulation 45(8)(a): Revision of high inflow period

- **Proposal:** the RPC may revise a high inflow period that has already been declared.

- **Concern:** the high inflow period affects hydro scheduling and the recovery of charges by hydro stations, and therefore the power purchase cost of beneficiary Discoms. Open-ended revision creates uncertainty and may reopen accounts that have already been settled.
- **Suggestions:**
    - Allow revision only on the basis of recorded hydrological data, with reasons published by the RPC.
    - Consult the beneficiaries before any revision and give them advance notice.
    - Make revisions prospective only, without reopening energy accounts or bills already issued.
    - Limit the number of revisions in a water year.

Regulation 45(8)(a), New proviso: Peak and off-peak declared capacity of thermal stations

- **Proposal:** a regional entity thermal station shall not declare lower capacity in peak hours than in off-peak hours, except in forced or partial outage. Otherwise, the lower of the two is taken as declared capacity for fixed charges.
- **Comment:** TNPDCL welcomes this provision. Beneficiaries pay full capacity charges and need the contracted capacity most during peak hours.
- **Suggestions:**
    - Require stations to report each partial outage to the RLDC with reasons, and have the RPC verify it, so that the exception is not used to avoid the rule.
    - Make clear that fuel shortage or commercial reasons do not qualify as partial outage.
    - Apply the lower declared capacity for the whole day, both for fixed charges and for computing peak and off-peak availability for incentives.
    - Have the RPC publish the instances where the lower capacity was applied in the monthly REA.

14. Regulation 45(16): Regulation of access to defaulting entities

- **General concern:** for a Discom, regulating access means cutting power to consumers, including essential services. Statutory charges such as DSM, congestion and reactive energy charges are billed weekly and are often revised, reconciled or disputed. Regulating access for such amounts is disproportionate.
- **Default trigger and notice:**
    - The term "default trigger date" is not defined in this clause. Define it, or refer to the relevant regulation.
    - Give a written notice of at least seven days to the entity, with a copy to the SLDC, before access is regulated.
- **Disputed and netted amounts:**
    - Do not regulate access where the undisputed amount has been paid and a discrepancy has been raised with the RPC.
    - Net amounts receivable by the entity from the pool account before declaring a default.
- **45(16)(a)(i), T-GNA including power exchange:**
    - Regulating short-term purchase entirely, including the power exchange, removes the Discom's main means of meeting peak demand and RE shortfalls. This leads directly to load shedding.
- **45(16)(a)(ii) and (iii), GNA short-term and long-term contracts:**
    - Progressive cuts of 5% a month in long-term schedules hit consumer supply while the Discom continues to pay capacity charges for the same contracts.
    - Begin any cut in long-term schedules only after a further notice and an opportunity to be heard.
- **45(16)(b), restoration:**
    - Restore access on the same day once proof of payment (UTR) is submitted, rather than up to one day after.

14.Regulation 45(17): Free power of State Government from Central Hydro stations

- **Proposal:** a State Government with a free power share in a Central Hydro Generating Station may sell it directly from the station bus bar, as per the procedure at Annexure 8.
- **Comment:** TNPDCL has no objection in principle, provided the beneficiaries of the station are not affected.
- **Suggestions:**
    - Ensure that sale of free power does not reduce the scheduled share or priority of the station's beneficiaries.
    - Bill transmission charges and losses for the free power sale to the State Government or its buyer, not to the beneficiaries.
    - Keep deviations arising from the free power sale in a separate account, so that they are not loaded on the beneficiaries' DSM accounts.

15. Regulation 46 – Unit Shutdown and beneficiary schedule revisions

Regulation 46(4)(a-i): Intimation of units proposed for USD

- **Proposal:** the generating station shall inform the RLDC and beneficiaries by 1430 Hrs of D-1 of the units proposed to be taken under USD.
- **Concern:** this leaves beneficiaries only one hour, up to 1530 Hrs, to assess demand and RE forecasts and decide whether to retain the units. By then the Day-Ahead Market has already closed, so a Discom cannot use it to cover any shortfall.
- **Suggestions:**
    - Advance the intimation to 1330 Hrs of D-1, or extend the beneficiaries' window to at least two hours.
    - The intimation should give the unit-wise MCR, minimum turn-down level, reasons for USD, and the notice period needed to bring the unit back.
    - Issue the intimation through the RLDC scheduling portal, so that all beneficiaries and SLDCs receive it at the same time.

Regulation 46(4)(a-ii): Retention of units by scheduling at least 50% MCR

- **Proposal:** beneficiaries may revise schedules by 1530 Hrs of D-1 to retain the units on bar, by scheduling at least 50% of MCR in all time blocks.
- **Concern:** for a station with several beneficiaries, the draft does not say whether 50% MCR is to be met jointly or by each beneficiary. A single beneficiary that needs the unit cannot keep it on bar if others reduce their requisition.
- **Suggestions:**
    - Clarify that the 50% MCR is the total schedule of all beneficiaries, including any sale of un-requisitioned surplus.
    - Allow a beneficiary to requisition power beyond its share, from capacity left unrequisitioned by others, to meet the threshold.
    - Allocate any compensation for part-load operation to the beneficiaries that chose to retain the unit, in proportion to their schedules.
    - Ensure that 50% MCR is consistent with the minimum turn-down level referred to in sub-clause (b).

Regulation 46(4)(b): Schedules final and binding after 1530 Hrs

- **Proposal:** once confirmed by 1530 Hrs of D-1, the revised requisition is final. No further reduction in drawal schedule is allowed, except while the station remains above minimum turn-down level.
- **Concern:** Tamil Nadu has a large share of wind and solar generation. When RE output turns out higher than forecast, the Discom has to reduce thermal schedules in real time. A rigid schedule forces it either to under-draw, and pay deviation charges, or to back down its own cheaper or must-run generation.
- **Suggestions:**
    - Allow downward revision in real time down to the minimum turn-down level for every unit on bar, not only for stations already above that level.
    - Allow revision in contingencies such as transmission constraints, grid security instructions or forced outages in the State.

- Allow beneficiaries to offer the power they cannot absorb for sale as un-requisitioned surplus or in the Real-Time Market, without losing their right to it.

Regulation 46(4)(b-i): Declaration of USD where 50% MCR is not achieved

- **Proposal:** the generating station may declare units under USD by 1600 Hrs of D-1 if a schedule of at least 50% MCR in all time blocks is not achieved.
- **Suggestions:**
  - State expressly that a station shall not declare USD where beneficiaries have met the 50% MCR threshold.
  - Require the station to declare, along with USD, the notice period and start-up time for bringing the unit back, so that Discoms can recall it to meet evening peak or a sudden RE shortfall.
  - Clarify who bears start-up costs when a unit under USD is recalled at the request of a beneficiary or the RLDC.

Regulation 46(4)(c) and (d): Revised timelines (1630 and 1700 Hrs)

- **Proposal:** the timelines in sub-clauses (c) and (d) move from 1430 to 1630 Hrs and from 1500 to 1700 Hrs.
- **Concern:** later finalisation of inter-state schedules leaves less time for the SLDC to finalise intra-state day-ahead schedules and commit State-owned units.
- **Suggestions:**
  - Align the revised timelines with SLDC scheduling timelines, in consultation with the SLDCs, before notification.
  - Ensure that final inter-state schedules are made available to SLDCs immediately after 1700 Hrs through the common scheduling portal.

Regulation 46(6): SCUC commitment and decommitment by NLDC

- **Proposal:** NLDC may run security constrained unit commitment (SCUC) at any time of the day to commit or decommit a unit for grid security. Schedules of a decommitted unit are adjusted as per the procedure at Annexure-9.
- **Concern:** decommitting a unit contracted by a Discom changes its supply portfolio without its consent. This may leave a shortfall to be met at a higher cost in the market, or cause deviation. The draft says nothing about who bears these costs.
- **Suggestions:**
    - Use SCUC to decommit a unit only for grid security, record the reasons, and publish them on the NLDC website.
    - Give prior intimation to the affected beneficiaries and SLDCs, with enough lead time for them to arrange replacement power.
    - Treat deviations caused by a decommitment as exempt from DSM charges for the affected beneficiaries.
    - Clarify the treatment of capacity charges for decommitted units, and recover the cost of committing or decommitting for grid security through the ancillary services pool, not from the beneficiaries of that station.

16. Regulation 47 – USD, off-bar DC and revival

Regulation 47(2): Planning USD and allocating requisitions

- **Proposal:** the generating station shall plan USD so that the maximum number of units remain on bar, keeping in view economy and efficiency.
- **Comment:** TNPDCL supports this principle.
- **Suggestions:**
    - Define "economy and efficiency". For example, where a unit must go under USD, the unit with the highest heat rate should be chosen.
    - Require the station to record and share with the RLDC and beneficiaries the reasons for its choice of unit.

Clause (2)(a): requisition met by other units on bar

- TNPDCL has no objection.

Clause (2)(b): pro-rata reduction where other units cannot meet the requisition

- **Concern:** if total requisition cannot be met by the units remaining on bar, the unit is in fact needed. Shutting it down and cutting every beneficiary's requisition pro-rata would deny Discoms power they have contracted and are paying for.
- **Suggestions:**
    - Do not allow USD where total requisition exceeds what the remaining on-bar units can supply. Pro-rata reduction should apply only where USD is directed by the RLDC or under SCUC.
    - Where reduction is unavoidable, intimate it with the USD notice so that beneficiaries can arrange replacement power.

Clause (2)(c): only running unit going under USD

- **Concern:** beneficiaries receive no power from the station but continue to pay its capacity charges.
- **Suggestions:**
    - Require the station to declare the time it needs to bring the unit back, and allow beneficiaries to recall it at short notice.
    - Allow beneficiaries to procure replacement power without any DSM liability for the period of transition as well as capacity charges liability of the USD unit.

Regulation 47(2a): Intimation of USD by 1800 Hrs of D-1

- **Concern:** the amendment to Regulation 46(4)(b-i) allows a station to declare USD by 1600 Hrs of D-1, while this clause allows intimation as late as 1800 Hrs. The two timelines are inconsistent. 1800 Hrs is also after final schedules are issued at 1700 Hrs and well after the Day-Ahead Market has closed. This leaves Discoms only the Real-Time Market to cover any shortfall.

- **Suggestions:**
    - Align this timeline with Regulation 46(4)(b-i), so that intimation is given by 1600 Hrs of D-1.
    - Issue the intimation through the RLDC scheduling portal to all beneficiaries and SLDCs at the same time.

Regulation 47(2b): On-bar DC, off-bar DC and capacity charges

- **Proposal:** on declaring USD, the station revises on-bar DC (considering ramp capability) and off-bar DC. Beneficiaries continue to pay capacity charges on total DC, including off-bar DC. Schedules for day D correspond only to on-bar units.
- **Concern:** beneficiaries would pay full capacity charges for capacity they cannot schedule on day D. This is acceptable only if the off-bar capacity is genuinely available for revival when called upon.
- **Suggestions:**
    - Recognise off-bar DC for capacity charges only where the station has declared its revival time (hot, warm and cold start) and remains able to meet it.
    - Have the RLDC verify on-bar DC, including the ramp rates used, so that on-bar DC is not understated.
    - Exclude off-bar DC when computing peak-hour availability for incentives.
    - Specify a maximum continuous period for USD, beyond which off-bar DC is not counted for capacity charges unless the beneficiaries agree.

Regulation 47(2c): Station choosing not to take USD below 50% MCR

- **Proposal:** if the station decides not to take units under USD despite schedules below 50% MCR, the requisitioned schedules are not changed.
- **Comment:** TNPDCL supports this provision.
- **Suggestion:** clarify that, as the decision is the station's own, it cannot claim compensation for part-load operation or degraded heat rate from the beneficiaries for that period.

Regulation 47(2d): Revival of units under USD

- **Proposal:** a unit under USD shall be revived when beneficiaries and/or the RLDC give a schedule at or above minimum turn-down level (MTL), as per the modalities of SCUC. If it fails to come on bar within the stipulated time, it is treated as under forced outage for DC until it comes on bar. The same applies to units committed under SCUC.
- **Comment:** TNPDCL welcomes treating a failure to revive as a forced outage. This gives off-bar DC a real meaning.
- **Suggestions:**
    - Specify the "stipulated time" in the regulation, linked to the hot, warm and cold start times declared by the station.
    - Treat the unit as under forced outage from the time block in which it should have come on bar, not from the time the failure is recorded.
    - Clarify whether a single beneficiary whose schedule alone is at or above MTL can require revival, or whether the schedules of all beneficiaries are added together.
    - Exempt beneficiaries from DSM charges for deviations caused by a delay in revival.
    - Clarify who bears start-up costs when a unit is revived at the request of a beneficiary or the RLDC.
    - Keep the MTL used here consistent with the 50% MCR threshold in Regulation 46(4).

17. Regulation 48(3)(f) – Alternate-source supply

Regulation 48(3)(f): Express consent of the buyer and sharing of net savings

- Proposal: the words "in terms of mutual consent including on sharing of net savings" are replaced by "with the express consent of the buyer (which may be in form of a standing consent) and in terms of mutual agreement on sharing of net savings".

- Comment: TNPDCL welcomes the move from general mutual consent to express consent of the buyer. The buyer bears the cost of supply and remains responsible to its consumers, so no change in the source or manner of supply should be made without the buyer's clear approval.
- Concerns on standing consent:
    - A standing consent with no limits could let the generating station act on it for long periods, without the buyer reviewing each instance.
    - The draft does not say what happens if the buyer and the generating station do not agree on sharing net savings.
- Suggestions:
    - Require a standing consent to be in writing and valid for a fixed period, not exceeding one year. It should state any limits on quantum, period and landed cost.
    - Allow the buyer to withdraw or modify a standing consent at any time with reasonable notice, for example one week.
    - Require the generating station to inform the buyer and the RLDC of each instance in which it acts on a standing consent, with the quantum and expected savings.
    - Specify the method of computing net savings, and have the RPC verify it in the monthly accounts.
    - Where no agreement on sharing is reached, provide a default sharing ratio specified by the Commission, with at least the major share going to the buyer.
    - Provide that the buyer's landed cost shall not exceed what it would have paid under the original schedule. Any additional transmission charges, losses or deviation charges arising from the arrangement should be borne by the generating station.
    - Ensure that the arrangement does not affect the station's declared capacity, availability or the buyer's renewable purchase obligation accounting, unless the buyer agrees.

18. Regulations 48 and 49 – Scheduling and revision timelines

TNPDCL supports moving schedule revisions closer to real time, as this will help Discoms manage RE forecast errors and reduce deviations. TNPDCL requests that the Second Phase be triggered only after a review of the First Phase and confirmation that systems are ready.

First Phase

Revision effective from the 6th time block instead of the 8th

- **Proposal:** in Regulations 48(2)(b), 48(3)(b), 49(3)(b), 49(4)(c), 49(5)(f) and the first proviso to Regulation 49(7), revisions take effect from the 6th time block instead of the 8th.
- **Comment:** TNPDCL welcomes this change. Tamil Nadu has a large share of wind and solar generation, and a shorter lead time lets the Discom correct its schedules sooner when RE output differs from forecast. This reduces deviation and DSM charges.
- **Concerns:**
    - Generating stations may not be able to ramp to a revised schedule within the shorter lead time. Beneficiaries should not bear deviation charges for that shortfall.
    - SLDCs must incorporate inter-state revisions into intra-state schedules within the same shorter time. Their scheduling software and procedures will need to change.
- **Suggestions:**
    - RLDCs should implement revisions within the declared ramp rates of each station. Any deviation caused by a station's failure to follow a valid revision should be charged to the station, not to the beneficiaries.
    - Make the revised schedules available to SLDCs immediately through the common scheduling portal.

- Allow a transition period of at least three months, with mock trials, before the First Phase takes effect, so that RLDC, SLDC and Discom systems can be upgraded.

Revised night-time timelines in Regulation 49(1)(q)(ii), (q)(iv) and (r)

- **Proposal:** the timelines are moved later by 10 to 15 minutes. In (q)(ii), 22.45 and 23.00 become 23.00 and 23.15. In (q)(iv), 23.15 becomes 23.30 and 23.00 becomes 23.15. In (r), 23.30 and 23.35 become 23.40 and 23.45.
- **Comment:** TNPDCL has no objection, as the later timelines give more time to account for the latest forecasts.
- **Suggestions:**
  - Confirm that the revised timelines remain in the correct sequence with each other and with the Real-Time Market sessions near midnight.
  - Ensure that the SLDC receives the final schedules for day D in time to issue intra-state schedules before the day begins.

Second Phase

Revision effective from the 5th time block

- **Comment:** TNPDCL supports the further reduction in principle, for the same reasons as the First Phase.
- **Suggestions:**
  - Trigger the Second Phase only after the First Phase has run for at least six months.
  - Before triggering it, have NLDC review the First Phase, covering generator response to revisions, deviations and system readiness. Publish the review for stakeholder comments.
  - Notify the date of the Second Phase at least three months in advance.

19. Regulation 59 – Repeal of 2009 congestion regulations

Regulation 59(5): Repeal of the 2009 Congestion Regulations

- **Proposal:** the CERC (Measures to relieve congestion in real time operation) Regulations, 2009, with all amendments, the rate of congestion charge and the procedures made under them, stand repealed from the date the Second Amendment takes effect.
- **Concern:** this clause repeals the rate of congestion charge and the procedures, but Clauses (6) and (7) say the same rate and procedure continue in force. As drafted, the provisions contradict each other.
- **Suggestions:**
    - Begin Clause (5) with "Subject to Clauses (6) and (7) of this Regulation".
    - Add a savings clause so that actions, statements, payments and proceedings already taken or pending under the 2009 Regulations continue to be governed by those Regulations.

Regulation 59(6): Continuation of the existing rate of congestion charge

- **Concern:** the existing rate was fixed for the 2009 framework, which did not provide for a charge in a wheeling region regardless of direction, as proposed in Regulation 30A(1)(b). Applying the old rate to this wider scope would extend the charge to cases the rate was never designed for.
- **Suggestions:**
    - Until a new rate is notified, apply the existing rate only to the cases covered by the 2009 Regulations, and not to the new wheeling-region provision.
    - Specify a time limit, for example six months, within which the Commission will notify the new rate after stakeholder consultation.

Regulation 59(7): Continuation of the existing detailed procedure

- **Concern:** the existing procedure does not cover the new elements of Regulation 30A. These include the wheeling-region provision, the RPC statement, payment

within 10 days with interest, and release within two working days. Applying Regulation 30A through a procedure written for a different framework will cause disputes.

- **Suggestions:**
  - Provide that the new elements of Regulation 30A shall apply only after the new detailed procedure under Regulation 30A(8) has been approved by the Commission.
  - In the meantime, levy the congestion charge only as provided under the 2009 Regulations and procedure.

20. Annexure-3 – Regional-entity bulk consumers

Large CTU-connected bulk consumers must independently forecast demand, submit schedules, account for deviations and meet associated reserve and grid-security costs. Such loads should not automatically be included in the host State DISCOM's demand or financial liabilities merely because of geographical location.

Separate accountability and SLDC coordination are necessary to avoid cross-subsidisation of privately attributable balancing costs by State consumers.

21. Annexure-4 – Payment-security timelines

The expression 'beyond due date' should be clarified in relation to corrected statements, banking days, accounting errors and revised payment demands. Default consequences should follow verified, communicated claims and should not automatically arise on the basis of an incorrect original statement.

TNPDCL requests harmonisation with dispute and default procedures, including reasonable cure periods.

22. Annexure-9 – Decommitment scheduling and SCUC settlement

Centrally directed decommitment and substitute SCUC-Up should not result in unverified additional charges to beneficiaries of the decommitted unit. The procedure should identify who bears start-up costs, incremental generation expenditure, transmission losses, savings

and deviation effects, and should protect the beneficiaries' ability to obtain contracted power.

SCUC decisions are undertaken for wider grid security and economy. The associated settlement should therefore be transparent and consistent with the applicable ancillary-service mechanism rather than automatically charged to an individual distribution licensee. Detailed worked illustrations and accounting methodology should precede implementation.

III. Consolidated submission of TNPDCL

TNPDCL supports the Hon'ble Commission's objectives of strengthening grid security, integrating renewable energy and storage, relieving congestion and moving scheduling closer to real time. However, several of the proposed provisions shift operational risk and cost onto distribution licensees, and through them onto consumers, without adequate safeguards. Taking the regulation-wise comments in Part II together, TNPDCL respectfully makes the following consolidated submission:

(1) **Commissioning flexibility must not dilute PPA obligations.** Extensions of interchange before COD, instalment-wise trial runs, unit-wise COD of pumped storage plants and scheduling of infirm power should remain operational permissions only. They should not alter the Scheduled Commissioning Date, liquidated damages, performance guarantees or any other right or remedy of the beneficiaries under the PPA. (Regulations 19(3), 22(3), 25A and 27)

(2) **COD under the Grid Code must be kept distinct from COD under the contract.** Declaration of commercial operation under the Grid Code should not, by itself, make the beneficiaries liable for tariff, capacity charges or any other payment. Such liability should begin only when the contractual conditions are met. Power generated in the intervening period should first be offered to the contracted buyer at a tariff not exceeding the PPA tariff. (Regulations 25A and 27(1))

(3) **Trial runs of storage must demonstrate the contracted service.** The trial run of a BESS or pumped storage plant should demonstrate rated MW, usable MWh, contracted discharge duration and, for PSP, pumping capability, for each instalment and for the full capacity. The seven-day notice for trial runs should be retained unless

the beneficiaries consent to a shorter period. Relaxation for transmission constraints should be confined to constraints that are not attributable to the generating station, and should be followed by de-rating, with refund of excess payments, where capacity is not demonstrated. (Regulations 21(1) and 22(3))

(4) **The congestion charge must be proportionate, transparent and not a second penalty.** The charge should apply only to deviations beyond DSM limits that actually aggravate a declared corridor constraint, in proportion to each entity's contribution. Deviations caused by uncleared market bids, outages of contracted generators and LDC instructions should be exempt. The pricing principle and a ceiling, a combined cap with DSM charges, adequate notice, mandatory withdrawal and block-wise supporting data should be laid down in the Regulation. Interest should be as per the LPS Rules, 2022. The charge should take effect only after the new procedure is approved and a six-month shadow settlement is completed, and the existing 2009 rate should not be extended to the new wheeling-region provision. (Regulations 3, 30A and 59)

(5) **Regulation of access must be the last resort and confined to admitted dues.** For a distribution licensee, regulation of access means load shedding to consumers, including essential services. It should not be applied for weekly statutory charges that are under revision, reconciliation or bona fide dispute. The default trigger date should be defined, a written notice of at least seven days should be given, receivables from the pool should be netted, a hearing should precede any cut in long-term schedules, and access should be restored on the same day on proof of payment. These provisions should be harmonised with the LPS Rules, 2022 and Annexure-4. (Regulations 3, 45(16) and Annexure-4)

(6) **Reserve obligations must be evidence-based and must not be duplicated.** Any change in the reserve estimation methodology should be supported by published studies and State-wise financial implications. Reserve capacity already contracted and funded by the States should be recognised, and only the verified net shortfall should be allocated. (Regulation 30(11)(k))

(7) **Unit shutdown and SCUC must protect the beneficiaries' access to contracted power.** The USD timelines should be advanced and made mutually consistent so that Discoms can act in the Day-Ahead Market. The 50% MCR threshold should be applied to the combined schedule of all beneficiaries. Real-time downward revision should remain available for RE variation. USD should not be permitted where the remaining units cannot meet the total requisition. Off-bar DC should count for capacity charges only where revival within the declared start-up time is assured, and failure to revive should be treated as forced outage. Costs of SCUC commitment and decommitment, start-up and related deviations should be recovered through the ancillary services pool and not from the beneficiaries of the affected station. (Regulations 46, 47 and Annexure-9)

(8) **Peak-hour availability and hydro scheduling should be safeguarded.** The proposed rule against lower peak-hour declared capacity is welcomed, subject to RPC verification of partial outages. Revision of the high inflow period should be prospective, based on recorded hydrological data and made after consulting the beneficiaries. Sale of free power by State Governments should not affect the beneficiaries' shares, transmission charges or DSM accounts. (Regulations 45(8)(a) and 45(17))

(9) **Alternate-source supply should rest on bounded consent.** Standing consent of the buyer should be in writing, time-bound, revocable and limited in quantum and landed cost. Net savings should be computed on a specified method and verified by the RPC, and the buyer's landed cost should not exceed that under the original schedule. (Regulation 48(3)(f))

(10) **Scheduling reforms should be phased in with system readiness.** The reduction of revision lead time to the 6th time block is supported, subject to a transition period of at least three months with mock trials, implementation within the stations' ramp rates and charging of deviations from non-compliance to the generating station. The Second Phase should be triggered only after at least six months of the First Phase, a published NLDC review and three months' advance notice. (Regulations 48 and 49)

(11) **Bulk consumers connected to the ISTS should bear their own costs.** Regional-entity bulk consumers should be separately responsible for forecasting, scheduling, deviation, reserve and grid-security costs, and should not be loaded on the host State Discom merely because of their location. (Annexure-3)

In view of the above, TNPDCL respectfully requests the Hon'ble Commission to:

(a) incorporate the provisos, clarifications and modifications suggested in Part II before finalising the Second Amendment;

(b) ensure that no additional charge, penalty or liability is imposed on distribution licensees for system inadequacy, generator-side constraints or centrally directed actions that are beyond their control;

(c) bring the congestion charge, the revised reserve methodology, the SCUC settlement and the revised scheduling timelines into force only after the related detailed procedures have been published for stakeholder comments and approved by the Commission, with adequate transition and trial periods.

R Srinivasan
dt 11.2020
Chief Financial Controller
Regulatory Cell