भारत सरकार Government of India
विद्युत मंत्रालय Ministry of Power
उत्तर पूर्वी क्षेत्रीय विद्युत समिति
North Eastern Regional Power Committee
एन ई आर पी सी कॉम्प्लेक्स, डोंग पारमाओ, लापालाङ, शिल्लोंग-७९३००६, मेघालय
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No. NERPC/Comml/Correspondence/2024/6029 Date: 21-10-2026

सेवा में /To,
Secretary, CERC,
6th, 7th & 8th Floors, Tower B, World Trade Centre,
Nauroji Nagar, New Delhi- 110029.

विषय/ Sub: केंद्रीय विद्युत नियामक आयोग (भारतीय विद्युत ग्रिड कोड) (दूसरा संशोधन) विनियम, 2026 के मसौदे के लिए टिप्पणियां और सुझाव के संबंध में।/ Comments & Suggestions For the Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026-reg.

Ref.

1. CERC Public Notification under file No. L-1/265/2022/CERC dated 21/09/2026

Sir/Madam,

With reference to the subject cited above and the notification under reference, please find enclosed herewith the comments and suggestions of NERPC, Shillong, on the Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026, for your kind consideration and necessary action.

भवदीय / Yours faithfully,

(बी. लिंगखोई /B. Lyngkhoi)
सदस्य सचिव/ Member Secretary

1. **Amendment to Regulation 19 of the Principal Regulation:**

In Draft Regulation

2(iii) RLDC may allow multiple extensions with a cumulative time extension for three months, after carefully examining the reasons for such extension.

Purposed Change

2(iii) RLDC, **in consultation with RPC**, may allow multiple extensions with a cumulative time extension for three months, after carefully examining the reasons for such extension.

Reasons:

The injection of infirm power by generating units and Energy Storage Systems, as well as any extension of the period permitted for such injection or deferment of the Commercial Operation Date (COD) of an upcoming unit or plant, has significant implications for regional power system operation and commercial arrangements. Such developments affect not only the concerned generating companies and Energy Storage Systems but also the beneficiaries dependent upon their scheduled availability and power supply.

Furthermore, timely information regarding the injection of infirm power and the anticipated COD of generating units is essential for resource adequacy planning, optimisation of the power portfolio, assessment of power availability, and other related operational and commercial considerations. These factors also influence the planning and coordination of scheduled maintenance of other generating units and associated power system elements, thereby contributing to the maintenance of a proper balance between generation and demand.

In view of the above, it is considered necessary that the RPC, being the regional coordinating forum for the stakeholders concerned, be consulted before RLDC permits any extension in the period of injection of infirm power or any deferment of the COD of an upcoming generating unit or plant, including Energy Storage Systems, wherever applicable.

Accordingly, it is proposed that the words “in consultation with RPC” be inserted in Regulation 2(iii), so as to ensure coordinated decision-making, timely dissemination of information to the stakeholders concerned, and due consideration of the regional implications of such extensions.

In Draft Regulation

2(iv) Concerned REGS or ESS (except Hydro PSP ESS) shall keep RLDC informed of the activities to be carried out on monthly basis due to which such extension has been sought by the entity.

Purposed Change

2(iv) Concerned REGS or ESS (except Hydro PSP ESS) shall keep RLDC **and RPC** informed of the activities to be carried out on monthly basis due to which such extension has been sought by the entity.

Reasons:

The injection of infirm power by generating units and Energy Storage Systems, as well as any extension of the period permitted for such injection or deferment of the Commercial Operation Date (COD) of an upcoming unit or plant, has significant implications for regional power system operation and commercial arrangements. Such developments affect not only the concerned generating companies and Energy Storage Systems but also the beneficiaries dependent upon their scheduled availability and power supply.

Furthermore, timely information regarding the injection of infirm power and the anticipated COD of generating units is essential for resource adequacy planning, optimisation of the power portfolio, assessment of power availability, and other related operational and commercial considerations. These factors also influence the planning and coordination of scheduled maintenance of other generating units and associated power system elements, thereby contributing to the maintenance of a proper balance between generation and demand.

In view of the above, it is considered necessary that the RPC, being the regional coordinating forum for the stakeholders concerned, keep track of the activities to be carried out by Concerned REGS or ESS (except Hydro PSP ESS) for the benefit of larger consumer and Grid Operation.

2. Amendment to Regulation 30 the Principal Regulations:

In Draft Regulation

No provision has been made for providing incentives to Energy Storage Systems (ESS) for delivering Primary Frequency Response.

Purposed Change

Suitable provisions may be incorporated to provide incentives for the following categories of Energy Storage Systems, whose tariff is determined under Section 62 of the Electricity Act, 2003, for providing Primary Frequency Response:

Pumped Storage Plants (PSPs): An incentive mechanism may be introduced for Pumped Storage Plants whose tariff is determined under Section 62 of the Electricity Act, 2003, for providing Primary Frequency Response, on lines similar to the provisions applicable to hydro generating stations under Clause (4) of Regulation 65 of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024.

Other Energy Storage Systems: An incentive mechanism may be introduced for Energy Storage Systems, excluding Pumped Storage Plants, whose tariff is determined under Section 62 of the Electricity Act, 2003, for providing Primary Frequency Response, on lines similar to the provisions applicable to thermal generating stations under Clause (5) of Regulation 62 of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024.

Reasons:

The increasing integration of renewable energy sources, particularly solar and wind power, into the electricity grid is likely to increase the requirement for primary frequency response and other frequency regulation services to maintain grid stability, system security and reliable power system operation. In this context, Energy Storage Systems, owing to their capability to respond rapidly to changes in grid frequency, can play a significant role in providing Primary Frequency Response and supporting grid frequency regulation.

The Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024, provide for incentives to eligible thermal and hydro generating stations whose tariffs are determined under Section 62 of the Electricity Act, 2003, for providing Primary Frequency Response. In particular, Clause (5) of Regulation 62 and Clause (4) of Regulation 65 prescribe incentive mechanisms for thermal and hydro generating stations, respectively, linked to their average monthly frequency response performance, subject to the applicable regulatory conditions.

However, the absence of a corresponding incentive mechanism for eligible Energy Storage Systems may limit the financial motivation for such systems

to maintain and provide the required primary frequency response capability. Extending a suitable performance-linked incentive mechanism to such Energy Storage Systems would encourage their effective participation in frequency regulation services and promote the availability of additional primary response reserves in the grid.

Accordingly, it is proposed that suitable provisions be incorporated in the Regulations to extend an incentive mechanism to Pumped Storage Plants and other eligible Energy Storage Systems, whose tariffs are determined under Section 62 of the Electricity Act, 2003, by adopting, with appropriate modifications, the principles applicable to hydro and thermal generating stations, respectively. Such a provision would promote technology-neutral participation, incentivise improved frequency response performance and strengthen grid stability and operational reliability in the context of increasing renewable energy integration.

3. Amendment to Regulation 46 the Principal Regulations:

In Draft Regulation

1 (a-ii) The beneficiaries may revise schedules by 1530 Hrs of 'D-1' day to retain such units on-bar by ensuring scheduling of at least 50% MCR for all time blocks.

3 (b-i) The generating station may declare units under USD by 1600 Hrs of 'D-1' day if the schedule of at least 50% of MCR in all time blocks is not achieved.

Purposed Change

1 (a-ii) The beneficiaries may revise schedules by 1530 Hrs of 'D-1' day to retain such units on-bar by ensuring scheduling **at a level not lower than the Minimum Turndown Level (MTL)** for all time blocks.

3 (b-i) The generating station may declare units under USD by 1600 Hrs of 'D-1' day if the schedule of at least **at a level of the Minimum Turndown Level (MTL)** in all time blocks is not achieved.

Reasons:
Several thermal generating stations are designed for efficient and stable operation at a minimum loading level of approximately 55% of their Maximum Continuous Rating (MCR). Operation of such units at a loading level lower than their design parameters may adversely affect operational efficiency, equipment reliability and overall generation costs.

In particular, reducing the minimum loading requirement from 55% MCR to 50% MCR may result in increased consumption of secondary fuel oil,

depending on the design and operating characteristics of the generating unit. Further, sustained operation at reduced loading levels may accelerate wear and tear of plant components, particularly those associated with the boiler and steam systems, where the equipment has not been specifically designed or modified to accommodate such operating conditions. Operation of boilers outside their intended design parameters may also pose operational challenges and adversely affect the safe and reliable operation of the generating station.

At the same time, retaining thermal generating units on-bar is important for maintaining adequate spinning reserves to address contingencies and ensuring sufficient ramping capability, particularly during the transition from solar to non-solar hours. Accordingly, the minimum loading requirement should be aligned with the Minimum Turndown Level (MTL) applicable to the concerned generating unit, rather than prescribing a uniform threshold of 50% MCR irrespective of the unit's design and operating characteristics.

Furthermore, requiring generating stations to operate below their applicable MTL may adversely affect their heat rate and auxiliary energy consumption. Such operation may also give rise to additional costs and compensation claims relating to heat rate and auxiliary energy consumption degradation, which may ultimately be borne by the beneficiaries in accordance with the applicable regulatory framework.

Further, certain units of thermal generating stations may be modified to operate at 40% of their MCR in accordance with the relevant flexibilization guidelines issued by the Central Electricity Authority (CEA). In respect of such units, maintaining a minimum loading of 50% MCR may not be necessary for their safe operation.

In view of the foregoing, it is proposed that the requirement of scheduling at least 50% MCR be replaced with a requirement to ensure scheduling at a level not lower than the applicable MTL for all time blocks. This would enable generating stations to operate within their prescribed technical limits, safeguard equipment reliability, minimise avoidable operational inefficiencies and associated costs, and ensure the availability of adequate spinning reserves and ramping capability for secure and reliable grid operation.

Accordingly, the proposed modification would protect the interests of beneficiaries by avoiding inefficient operation of thermal generating units below their applicable MTL, while allowing such units to remain on-bar where technically and economically justified or, where appropriate, to be taken under reserve shutdown (USD), subject to the applicable provisions of the Regulations and system requirements.

4. Amendment to Regulation 47 the Principal Regulations:

In Draft Regulation

1 (2c) In case the generating station decides not to take unit(s) under USD, despite getting a schedule below 50% of MCR for some or all-time block(s) in a day, the requisitioned schedules shall not undergo any change under Clause (2) of this Regulation.

Purposed Change

1 (2c) In case the generating station decides not to take unit(s) under USD, despite getting a schedule below **Minimum Turndown Level (MTL)** for some or all-time block(s) in a day, the requisitioned schedules shall not undergo any change under Clause (2) of this Regulation.

Reasons:

Several thermal generating stations are designed for efficient and stable operation at a minimum loading level of approximately 55% of their Maximum Continuous Rating (MCR). Operation of such units at a loading level lower than their design parameters may adversely affect operational efficiency, equipment reliability and overall generation costs.

In particular, reducing the minimum loading requirement from 55% MCR to 50% MCR may result in increased consumption of secondary fuel oil, depending on the design and operating characteristics of the generating unit. Further, sustained operation at reduced loading levels may accelerate wear and tear of plant components, particularly those associated with the boiler and steam systems, where the equipment has not been specifically designed or modified to accommodate such operating conditions. Operation of boilers outside their intended design parameters may also pose operational challenges and adversely affect the safe and reliable operation of the generating station.

At the same time, retaining thermal generating units on-bar is important for maintaining adequate spinning reserves to address contingencies and ensuring sufficient ramping capability, particularly during the transition from solar to non-solar hours. Accordingly, the minimum loading requirement should be aligned with the Minimum Turndown Level (MTL) applicable to the concerned generating unit, rather than prescribing a uniform threshold of 50% MCR irrespective of the unit's design and operating characteristics.

Furthermore, requiring generating stations to operate below their applicable MTL may adversely affect their heat rate and auxiliary energy consumption. Such operation may also give rise to additional costs and compensation claims relating to heat rate and auxiliary energy consumption degradation, which may ultimately be borne by the beneficiaries in accordance with the applicable regulatory framework.

Further, certain units of thermal generating stations may be modified to operate at 40% of their MCR in accordance with the relevant flexibilization guidelines issued by the Central Electricity Authority (CEA). In respect of such units, maintaining a minimum loading of 50% MCR may not be necessary for their safe operation.

In view of the foregoing, it is proposed that the requirement of scheduling at least 50% MCR be replaced with a requirement to ensure scheduling at a level not lower than the applicable MTL for all time blocks. This would enable generating stations to operate within their prescribed technical limits, safeguard equipment reliability, minimise avoidable operational inefficiencies and associated costs, and ensure the availability of adequate spinning reserves and ramping capability for secure and reliable grid operation.

Accordingly, the proposed modification would protect the interests of beneficiaries by avoiding inefficient operation of thermal generating units below their applicable MTL, while allowing such units to remain on-bar where technically and economically justified or, where appropriate, to be taken under reserve shutdown (USD), subject to the applicable provisions of the Regulations and system requirements.

5. Annexure-8:

In Draft Regulation

4.6 Once such free power share which is scheduled to SG is sold by the SG, the corresponding injection schedule will be reflected in the scheduled generation for the CHGS (s).

Purposed Change

4.6 Once such free power share which is scheduled to SG, the corresponding injection schedule will be reflected in the scheduled generation for the CHGS (s) **irrespective whether such free power disposed by SG or not.**

Reasons:

There may be instances where, despite the scheduling of free power in favour of the State Government (SG), the State Government is unable to dispose of the allocated power through the Day-Ahead Market (DAM), bilateral transactions or any other available mechanism. Consequently, the power scheduled for injection from the Central Hydroelectric Generating Station (CHGS) may be lower than the generation potential of the station, notwithstanding the availability of sufficient water for generation.

For instance, the State Government may place a sell bid in the electricity market at a specified price of ₹X/kWh; however, if the market-clearing price is lower than the bid price, the sell bid may remain uncleared, resulting in

the inability to dispose of the corresponding quantum of free power through the market. Such a situation may arise even where the generating station has sufficient water availability to generate the power, the generating station not able to rut at full capacity.

The issue assumes particular significance in the case of run-of-river (RoR) hydroelectric generating stations and stations having limited water storage capacity. Further During periods of high inflows, CHGSs may have insufficient storage capacity to conserve the available water for subsequent generation. Consequently, the inability to schedule and inject the available hydroelectric power may result in the unintended curtailment or underutilisation of the available hydroelectric generation potential, including the avoidable spillage of water.

In such circumstances, where the free power allocated to the State Government remains unsold in the DAM, the State Government may make further efforts to dispose of the unutilised power through the Real-Time Market (RTM) or other permissible mechanisms. However, even after making all reasonable efforts to sell the power, a portion of the available free power may remain undisposed of. In such cases, the State Government may receive monetary compensation through the applicable Deviation Settlement Mechanism (DSM) provisions for under-injection, subject to the prevailing regulatory framework.

Further, the quantum of power scheduled from the CHGS vis-à-vis the quantum of power actually disposed of by the State Government can be ascertained at the time of closure of the RTM gate, thereby providing advance visibility of the likely surplus injection into the grid. Such information may be utilised by the National Load Despatch Centre (NLDC) to assess the requirement for downward balancing and, wherever technically feasible and permissible under the applicable regulations, to schedule downward ancillary services from the available ancillary reserves in advance.

Accordingly, an appropriate mechanism for advance coordination and balancing of such surplus hydroelectric power may help minimise unintended curtailment of hydroelectric generation, facilitate optimal utilisation of available water resources and maintain grid security by addressing the potential mismatch between scheduled generation and electricity demand.

In Draft Regulation

Appendix-I

Declared capacity of Central Hydro Generating Station (on D-1 day by 6 am) **(A)**	% Share and quantum of allocation of free power share of State Govt.in Central Hydro Generating Station **(B)**	Allocated share to the state (State DISCOMS) **(C)**	Entitlement of State Government as free power for sale on D day **(D)**	Power sold by the State Government in DAM on D-1 Day for D day **(E)**	Injection schedule of Central Hydro Generating Station on D day to State DISCOMS **(F)**	Total Scheduled generation of Central Hydro Generating Station at its bus on for sale on D day **(G=D+F)**	Revised DC/ schedule by Central Hydro Generating Station due to any reason/ partial outage on D day **(H)**	Revised entitlement of State Government as free power for sale on D day **(I)**	Power already sold by the State Govt. in DAM **(J=E)**	Revised Hydro Station Scheduled generation on D day to State Discoms **(K)**	Total scheduled Generation for D day at Central Hydro Generating Station bus bar) **(L=J+K)**	Actual generation by the Hydro Generating Station on D day **(M)**	Purchase / Sale of power from the market by State Govt. on D day **(N)**	Deviation of Central Hydro Generating Station **O=L-(I+M)**	Deviation of State Govt. (Power sold in the DAM- Actual Injection (i.e. revised entitlement of State Govt. against free power in Hydro Generating Station + Purchase of power by the state Govt. in RTM) **P= J-(I+N)**	**Remarks**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	500 MW	60 MW	0 MW	0 MW	**No deviation applicable**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	500 MW	40 MW	0 MW	-20 MW	**20 MW under\drawal by the State Government**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	450 MW	60 MW	-50 MW	0 MW	**50 MW under injection by the Hydro Generating Station**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	550 MW	60 MW	50 MW	0 MW	**50 MW over injection by the Hydro Generating Station**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	500 MW	0 MW	0 MW	-60 MW	**60 MW underdrawal by the State Government**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 W	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	400 MW	0 MW	-100 MW	-60 MW	**100 MW under injection by the Hydro Generating Station** **60 MW underdrawal by the State Government**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	550 MW	0 MW	50 MW	-60 MW	**50 MW over injection by the Hydro Generating Station** **60 MW underdrawal by the State Government**

Purposed Change

Appendix-I

Declared capacity of Central Hydro Generating Station (on D-1 day by 6 am) **(A)**	% Share and quantum of allocation of free power share of State Govt.in Central Hydro Generating Station **(B)**	Allocated share to the state (State DISCOMS) **(C)**	Entitlement of State Government as free power for sale on D day **(D)**	Power sold by the State Government in DAM on D-1 Day for D day **(E)**	Injection schedule of Central Hydro Generating Station on D day to State DISCOMS **(F)**	Total Scheduled generation of Central Hydro Generating Station at its bus on for sale on D day **(G=D+F)**	Revised DC/ schedule by Central Hydro Generating Station due to any reason/ partial outage on D day **(H)**	Revised entitlement of State Government as free power for sale on D day **(I)**	Power already sold by the State Govt. in DAM **(J=E)**	Revised Hydro Station Scheduled generation on D day to State Discoms **(K)**	Total scheduled Generation for D day at Central Hydro Generating Station bus bar) **(L=J+K)**	Actual generation by the Hydro Generating Station on D day **(M)**	Purchase / Sale of power from the market by State Govt. on D day **(N)**	Deviation of Central Hydro Generating Station **O=L-(I+M)**	Deviation of State Govt. (Power sold in the DAM- Actual Injection (i.e. revised entitlement of State Govt. against free power in Hydro Generating Station + Purchase of power by the state Govt. in RTM) **P= J-(I+N)**	**Remarks**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	500 MW	60 MW	0 MW	0 MW	**No deviation applicable**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	500 MW	40 MW	0 MW	20 MW	**20 MW Overdrawal by the State Government**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	450 MW	60 MW	-50 MW	0 MW	**50 MW under injection by the Hydro Generating Station**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	550 MW	60 MW	50 MW	0 MW	**50 MW over injection by the Hydro Generating Station**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	500 MW	0 MW	0 MW	60 MW	**60 MW Overdrawal by the State Government**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 W	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	400 MW	0 MW	-100 MW	60 MW	**100 MW under injection by the Hydro Generating Station** **60 MW Overdrawal by the State Government**
1000 MW	12%/ 120 MW	880 MW	120 MW	120 MW	880 MW	1000 MW	500 MW	60 MW	120 MW	440 MW	500 MW	550 MW	0 MW	50 MW	60 MW	**50 MW over injection by the Hydro Generating Station** **60 MW Overdrawal by the State Government**

Reasons:

Since the State Government (SG), in its capacity as a buyer entity, is subject to the provisions of the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2024, and the amendments thereto, its deviation is required to be computed in accordance with the applicable provisions of the said Regulations.

As per Clause-3 of Regulation -7 of the CERC DSM Regulations, 2024, the deviation of a buyer entity (DBUY), in MWh, is calculated as follows:

DBUY (in MWh) = Actual Drawal (in MWh) − Scheduled Drawal (in MWh).

Further, as per Clause 4.7 of Annexure-8 of this Regulations, the power sold in the power market is to be considered as the actual drawal quantum of the State Government. Accordingly, the actual schedule of power allocated to the State Government from the CHGS(s), together with the power purchased/Sold from the market, is required to be considered while determining its scheduled drawal, in accordance with the applicable regulatory provisions.

For illustration, where the State Government sells 120 MWh of power in the market, receives a schedule of 60 MWh from the CHGS(s), and purchases 40 MWh from the market, its deviation would be calculated as follows:

Actual drawal: 120 MWh (power sold in the market).

Scheduled drawal: 60 MWh (scheduled power from CHGSs) + 40 MWh (power purchased from the market) = 100 MWh.

Deviation (DBUY): 120 MWh − 100 MWh = +20 MWh (overdrawal).

Accordingly, in the above illustration, the State Government would be deemed to have overdrawn 20 MWh from the grid. This arises because the quantum of power sold in the market exceeds the aggregate scheduled power available to the State Government from the CHGS(s) and market purchases. Consequently, the State Government would be liable for the applicable DSM charges in respect of such deviation, in accordance with the CERC DSM Regulations, 2024, and the amendments thereto.