एनएचपीसी लिमिटेड
(भारत सरकार का एक नवरत्न उद्यम)
NHPC Limited
(A Government of India Navratna Enterprise)

CIN: L40101HR1975GOI032564

Great Place To Work. Certified JAN 2026-JAN 2027 INDIA

वाणिज्यिक विभाग
Commercial Department
एनएचपीसी ऑफिस कॉम्प्लेक्स, सैक्टर-33,
फ़रीदाबाद (हरियाणा)-121003
NHPC Office Complex, sector-33,
Faridabad (Haryana)-121003
फोन/Phone: 0129-2259923
ईमेल/Email: hod-commercial-co@nhpc.nic.in,
वैबसाइट/Website: www.nhpcindia.com

संख्या: एनएच/वाणिज्यिक/सीईआरसी/2026/750 दिनांक: 28.10.2026

सचिव

केंद्रीय विद्युत विनियामक आयोग

7वीं मंजिल, टॉवर-बी, वर्ल्ड ट्रेड सेंटर

ब्लॉक-एफ, नौरोजी नगर, सफदरजंग एन्क्लेव,

नई दिल्ली – 110029

विषय: केंद्रीय विद्युत विनियामक आयोग (भारतीय विद्युत ग्रिड कोड) (द्वितीय संशोधन) विनियम, 2026 के प्रारूप पर एनएचपीसी की टिप्पणियाँ।

संदर्भ: CERC लोक सूचना संख्या No L-1/265/2022/CERC दिनांक 21.09.2026

CERC लोक सूचना संख्या No L-1/265/2022/CERC दिनांक 22.10.2026

महोदय,

उपरोक्त विषय पर कृपया संलग्न पत्र प्राप्त करे।

धन्यवाद।

संलग्न: यथोपरि।

भवदीय,

MUKESH KUMAR MEENA

Digitally signed by MUKESH KUMAR MEENA
Date: 2026.10.28 11:13:34 +05'30'

(मुकेश कुमार मीणा)

महाप्रबंधक (वाणिज्यिक)

एनएचपीसी लिमिटेड
(भारत सरकार का एक नवरत्न उद्यम)
NHPC Limited
(A Government of India Navratna Enterprise)

CIN: L40101HR1975GOI032564

Great Place To Work. Certified JAN 2026-JAN 2027 INDIA

वाणिज्यिक विभाग
Commercial Department
एनएचपीसी ऑफिस कॉम्प्लेक्स, सैक्टर-33,
फ़रीदाबाद (हरियाणा)-121003
NHPC Office Complex, sector-33,
Faridabad (Haryana)-121003
फोन/Phone: 0129-2259923
ईमेल/Email: hod-commercial-co@nhpc.nic.in,
वैबसाइट/Website: www.nhpcindia.com

No. NH/Commercial/CERC/2026/750 **Date: 28.10.2026**

The Secretary
Central Electricity Regulatory Commission,
7th Floor, Tower-B, World Trade Centre
Block-F, Nauroji Nagar, Safdurjung Enclave,
New Delhi- 110 029

Sub.: Comments of NHPC on Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026.

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

Sir

In reference to above public notices dated 21.092026 and 22.10.2026, the comments / suggestions of NHPC on the draft CERC (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026 are enclosed for further necessary action. The comments / suggestions have been uploaded through SAUDAMINI portal under 'e-Regulation'.

Thanking You,

Encl.: As above

Yours Sincerely,

MUKESH KUMAR MEENA
Digitally signed by MUKESH KUMAR MEENA
Date: 2026.10.28 11:13:55 +05'30'

(Mukesh Kumar Meena)
General Manager (Comml.)

Comments of NHPC on the draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026

The Hon'ble Central Electricity Regulatory Commission (CERC) has issued the draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026, inviting comments and suggestions from stakeholders. Upon examination of the proposed amendments and taking into consideration the operational difficulties encountered in the implementation of the existing Principal Regulations, NHPC Limited hereby submits its comments and suggestions on the proposed amendments, as detailed below, for the kind consideration of the Hon'ble Commission.

1 Amendment to Regulation 46 of the Principal Regulations:

Hon'ble Commission have proposed amendment in the process of SCUC to be undertaken on day ahead basis in respect of regional entity generating station or units, for which tariff is determined under Section 62 of the Act. In the proposed amendment in sub-clause (b-i) of Clause (4) of Regulation 46, Hon'ble Commission has proposed that 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. Then in sub-clause (c) of Clause (4) of Regulation 46, hon'ble Commission has proposed to substitute number "1430" with "1630" in the principal regulations.

Thus, the proposed amended sub-clause (c) of Clause (4) of Regulation 46 is as under:

Quote

"(c) After 1630 Hrs, the NLDC in coordination with RLDCs shall prepare the final list of such generating units that are likely to go below their minimum turndown level and

such generating units shall be stacked as per merit order, that is, in the order of the lowest energy charge to the highest energy charge. The generating units so identified shall be considered for undertaking SCUC."

Unquote

From reading of above, it is understood that the NLDC in coordination with RLDCs shall prepare the final list of such generating units that are likely to go below their minimum turndown level, whereas in sub-clause (b-i), the generating station has been given the option to 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. Thus, it seems to be contradiction between proposed sub-clause (b-i) and sub-clause (c) of Clause (4) of Regulation 46.

In view of above, it is proposed to amend sub-clause (c) of Clause (4) of Regulation 46 as under:

Quote

"(c) After 1630 Hrs, the NLDC in coordination with RLDCs shall prepare the final list of such generating units ***which have been declared under USD by the generating station as the schedule of at least 50% of MCR in all time blocks is not achieved*** *and such generating units shall be stacked as per merit order, that is, in the order of the lowest energy charge to the highest energy charge. The generating units so identified shall be considered for undertaking SCUC."*

Unquote

2 Annexure-8 "Procedure to facilitate scheduling and accounting of Free Power share of State Govt. from bus bar of Central Hydro Generating Station"

2.1 Clause 4.6 of Annexure-8

Hon'ble Commission in Clause 4 of Annexure-8 has laid down the procedure for scheduling of free power share of State Govt. from bus bar of Central Hydro Generating Station (CGHS). In sub-clause 4.6, it has been proposed that "*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).*"

From the unilateral reading of sub-clause 4.6, it seems that if the SG does not sell the free power share scheduled to SG the same shall not be reflected in the schedule generation for the CGHS.

This interpretation has a possible unintended consequence as the CHGS's scheduled generation could become lower than its DC/available generation by the SG's unsold free-power quantum, even though that quantum is otherwise part of the SG's entitlement.

For example:

Particular	**MW**
CHGS DC	1,000
Other beneficiaries' schedule	880
SG free-power entitlement	120
SG sells free power	**No**

CHGS schedule under literal 4.6	880

Thus, 120 MW of DC remains unscheduled merely because SG did not sell its free power. This is the unintentional consequence of Clause 4.6 of Annexure-8. Further, the draft does not expressly clarify what happens to this unsold free-power entitlement and the table in Appendix-I of Annexure-8 only establish how the adjustment works once a sale takes place, but it does not address the scenario of unsold free power.

In view of above, Hon'ble Commission is requested to clarify whether unsold free power by SG shall continue to form part of the scheduled generation of the CHGS or remain unscheduled. The treatment may also be aligned with the mechanism illustrated in Appendix-I of Annexure-8 so that the scheduling of the CHGS is not left ambiguous merely on account of non-sale of the SG's free power.

Alternatively, it is proposed to modify Clause 4.6 of Annexure-8 as under:

Quote

"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).

Provided that in case complete/part free power share which is scheduled to SG is not sold by the SG, the same shall be scheduled to distribution licensee of the State and will be reflected in the scheduled generation for the CHGS (s)".

Unquote

2.2 Appendix-I of Annexure-8

Hon'ble Commission in Appendix-I of Annexure-8 has given examples of various scenarios for scheduling of free power and computation of deviation for a particular time block. On detailed analysis of the Appendix-I of Annexure-8, certain discrepancies have been observed which are as under:

1. 'Total scheduled Generation for D day at Central Hydro Generating Station bus bar' (column L) has been defined as sum of 'Power already sold by the State Govt. in DAM' (column J) and 'Revised Hydro Station Scheduled generation on D day to State Discoms' (column K), which works out to 560 MW whereas in the table it shown as 500 MW in all the cases. On analysis of the table, it seems that 'Total scheduled Generation for D day at Central Hydro Generating Station bus bar' (column L) has been calculated as sum of 'Revised entitlement of State Government as free power for sale on D day' (column I) and 'Revised Hydro Station Scheduled generation on D day to State Discoms' (column K).

2. 'Deviation of Central Hydro Generating Station' (Column O) has been defined as difference between Total scheduled Generation for D day at Central Hydro Generating Station bus bar (L) and sum of 'Revised entitlement of State Government as free power for sale on D day' (Column I) and 'Actual generation by the Hydro Generating Station on D day' (Column M) i.e. {O=L-(I+M)}. However, Column-O has been calculated as difference of 'Actual generation by the Hydro Generating Station on D day' (Column M) and 'Total scheduled Generation for D day at Central Hydro Generating Station bus bar' (Column L) i.e. (O = M – L).

3. The sign convention in Deviation of Central Hydro Generating Station (Column O) and Deviation of State Govt. (Column P) (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) is coming opposite to the sign convention shown in the table when calculated as per the formula defined.

4. After calculating the values as defined in the formula mentioned in Row-1 of the table (Appendix-I of Annexure-8), it is observed that formula defined worked only when the schedule is revised to 50% of actual schedule and that too with opposite sign convention. However, for any other percentage the formula does not give correct results for Column O i.e. 'Deviation of central hydro generating station'. An illustration of the same when the schedule is revised from 1000 MW to 800MW is shown below.

Declared capacity of Central Hydro Generating Station (on D-1 day by 6 am)	**(A)**	1000 MW
% Share and quantum of allocation of free power share of State Govt.in Central Hydro Generating Station	**(B)**	120 MW
Allocated share to the state (State DISCOMS)	**(C = A - B)**	880 MW
Entitlement of State Government as free power for sale on D day	**(D = B)**	120 MW
Power sold by the State Government in DAM on D-1 Day for D day	**(E)**	120 MW

Injection schedule of Central Hydro Generating Station on D day to State DISCOMS	**(F)**	880 MW
Total Scheduled generation of Central Hydro Generating Station at its bus on for sale on D day	**(G = D + F)**	1000 MW
Revised DC/ schedule by Central Hydro Generating Station due to any reason/ partial outage on D day	**(H)**	800 MW
Revised entitlement of State Government as free power for sale on D day	**(I)**	96 MW
Power already sold by the State Govt. in DAM	**(J = E)**	120 MW
Revised Hydro Station Scheduled generation on D day to State Discoms	**(K = H - I)**	704 MW
Total scheduled Generation for D day at Central Hydro Generating Station bus bar)	**(L = J + K)**	824 MW
Actual generation by the Hydro Generating Station on D day	**(M)**	800 MW
Purchase / Sale of power from the market by State Govt. on D day	**(N)**	0 MW
Deviation of Central Hydro Generating Station	**O=L-(I+M)**	-72 MW
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)**	24 MW overdrawal by state govt.

From above table, it can be seen that deviation of Central Hydro generating station works out to (-)72 MW whereas the actual generation is as per revised schedule and deviation of Central Hydro generating station should be Zero.

Similarly, Deviation of SG work out to 24 MW (over drawal by SG) whereas the Deviation of SG should be (-) 24 MW (under drawal by SG).

Therefore, the formula in the table has to be defined such that it gives accurate result for all the scenarios. In this regard, NHPC has prepared Appendix-I which works in all the scenarios, whether it is increase or decrease in schedule due to revision of schedule.

The modified Appendix-I as per comments is attached as Annexure-I.

2.3 Clause 3.2.4 of Annexure-8

Clause 3.2.4 of Annexure-8 provides that Monthly RLDC charges corresponding to the free share of power shall be payable by the SG to the concerned CHGS (s).

The proposed amendment providing that monthly RLDC charges corresponding to the free share of power shall be payable by the State Government (SG) to the concerned Central Hydro Generating Station(s) (CHGS) is a welcome step.

The amendment is appropriate because the free-power entitlement of the beneficiary State Government arises under the applicable statutory and regulatory framework. The corresponding RLDC charges attributable to that share should be transparently allocated to the beneficiary of the free power, in accordance with the prescribed settlement mechanism.

The provision would help ensure that the CHGS does not have to absorb or finance RLDC charges attributable to the State Government's free-power share, while maintaining clear accounting between the generating station and the beneficiary State.

The amendment would also improve transparency by linking the free-power entitlement to the corresponding RLDC charges.

2.4 Clause 5.5 of Annexure-8

Clause 5.5 of Annexure-8 provides that SG and CHGS(s) shall directly settle the DSM charges with the Regional Pool Account. This is a welcome step because it clarifies the settlement responsibility of the State Government (SG) and Central Hydro Generating Station(s) (CHGS).

However, it is important to ensure that the proposed mechanism does not result in duplication of DSM charges in respect of the same deviation.

DSM charges may arise from deviations attributable to the State Government's scheduling or drawal obligations and from deviations attributable to the generating station's declared capacity, schedule or injection. The procedure should clearly distinguish these responsibilities by entity, cause, quantum and time block.

Accordingly, Regulation 5.5 should clarify that direct settlement by the SG and CHGS(s) is based on the deviation attributable to each entity and does not result in duplicate recovery for the same deviation, quantum and time block. This clarification should not remove liability where a deviation is demonstrably attributable to the entity concerned.

Therefore, it is proposed that the following proviso may be added to Clause 5.5 of Annexure-8:

Quote

"Provided that DSM charges settled directly by the SG and CHGS(s) with the Regional Pool Account shall be determined separately on the basis of the deviation attributable to each entity, cause, quantum and time block. The same deviation component shall not be recovered more than once, without prejudice to liability for any distinct deviation attributable to the relevant entity."

Unquote

3 Amendment to Regulation 25 of the Principal Regulations:

Hon'ble Commission has proposed addition of a new Regulation 25A to be added after Regulation 25 of the Principal Regulations as under:

Quote

"25A Scheduling of infirm Power

(1) The scheduling of infirm power shall be allowed only post issuance of a certificate of successful trial run as per Regulation 25 of these Regulations.

(2) If the generating station or ESS has entered into a contract either directly or through REIA or intermediary procurer for sale of power from such generating station or ESS, and such contract have specific provisions for treatment of sale of power prior to achieving commercial operation, the same shall be scheduled to the buyer(s) as per the provisions of such Contract.

Unquote

The proposed insertion of Regulation 25A regarding scheduling of infirm power is noted. However, Regulation 25A(1), which permits scheduling only after issuance of a certificate of successful trial run, may require a limited clarification for hydro generating stations to ensure that energy injected during authorised commissioning and testing is properly scheduled and accounted for.

Hydro generating stations generally undergo a sequence of commissioning activities, including synchronisation, testing, trial operation and performance demonstration of individual generating units. During these commissioning activities, infirm power is injected into grid..

While such power cannot be scheduled prior to issuance of the successful trial-run certificate, its injection may be permitted by the concerned RLDC, subject to grid security requirements. However, the applicable DSM Regulations do not prescribe a specific rate for settlement of such infirm power. Consequently, the generating station may be required to account for the injection as a deviation without any specified compensation for the energy injected.

This issue is particularly significant for hydro generating stations, where water availability is often seasonal and prolonged non-utilisation of available inflows may result in avoidable spillage for instance: the period between notice of trial run and commencement of trial run or period after trial run and successful declaration of trial run. There may be instances when grid frequency is low and the grid could benefit from additional hydro generation, but a generating station may be unable to utilise available water for generation, despite the grid potentially benefiting from such generation, owing to the absence of a prescribed settlement rate for infirm power

injected before the successful trial-run certificate is issued. This results in the loss of potential energy generation and inefficient utilisation of available water resources. Accordingly, while the restriction on scheduling before successful completion of the trial run may be retained, an appropriate rate should be provided for settlement of infirm power injected with prior RLDC approval.

Further, in the case of hydro generating stations governed by Section 62 of the Electricity Act, 2003, any revenue earned from the sale or settlement of infirm power during the pre-trial-run period, if permitted under the applicable regulations, may be adjusted against the capital cost as per Regulation 6 of CERC Tariff Regulations 2024. Such adjustment would reduce the capital cost considered for tariff determination and, consequently, the tariff burden on beneficiaries. Thus, providing an appropriate rate for such infirm power would not only promote efficient utilisation of available water resources but also facilitate the sharing of the resulting financial benefits with the beneficiaries.

In view of the above, NHPC requests the Hon'ble Commission to retain the proposed restriction on scheduling of power prior to issuance of the successful trial-run certificate, while separately providing a specific settlement rate for infirm power injected by hydro generating stations during commissioning and testing, subject to prior RLDC approval and compliance with grid security and metering requirements.

Accordingly, it is suggested that Regulation 25A(1) may be retained as proposed, with an additional provision under the DSM Regulations prescribing the settlement rate for infirm power injected by hydro generating stations prior to issuance of the successful trial-run certificate, subject to prior approval of the concerned RLDC.

Comments of NHPC on the draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026

4 Introduction of Regulation 30A "Congestion Charges"

Hon'ble Commission has proposed addition of new Regulation 30A after Regulation 30 of Principal regulations as under:

Quote

"30A. CONGESTION CHARGE

(1) Applicability of Congestion Charge.

(a) The congestion charge shall be payable by a Regional entity or entities causing congestion in the inter-regional link or intra-regional link and receivable by a Regional entity or entities relieving congestion. Congestion charges would be levied for:

(i) over drawal or under-injection in the importing control area

(ii) under drawal or over-injection in the exporting control area

Unquote

The proposed Regulation 30A provides for levy of congestion charges on Regional Entity(ies) causing congestion in an inter-regional or intra-regional link. The stated objective of assigning congestion costs to the entity causing or materially contributing to congestion is understood. For effective implementation, the provision should also specify a transparent method for establishing causation and quantifying the incremental contribution of the relevant deviation.

While the objective of the proposed provision to assign the cost of congestion to the entity causing congestion is appreciated, it is submitted that the provision needs to be seen in conjunction with the existing mechanism of **Regional Transmission Deviation Charges (RTDA)**, particularly in the case of Hydro Generating Stations.

Hydro generating stations may already be subject to deviation-related financial consequences under the applicable DSM framework, including Regional Transmission Deviation Charges (RTDA), wherever applicable. If the same deviation or the same component of deviation is also used to levy a separate congestion charge under Regulation 30A, the framework could result in overlapping recovery unless the two charges and their respective purposes are clearly distinguished.

Overlapping charges may create a disproportionate liability, particularly where the deviation is not within the generating station's reasonable control or does not cause or materially contribute to the identified congestion. The appropriate test should be causation and incremental impact, not deviation alone.

Hydro generation depends on hydrological and hydraulic conditions and is subject to reservoir levels, inflows, irrigation and environmental releases, flood management, dam safety, unit availability and system instructions. Hydro stations may also vary generation in response to lawful directions from the System Operator to maintain grid security, frequency, balancing or manage transmission constraints. Such directions and constraints should be considered when attributing congestion.

Accordingly, a deviation from schedule should not, by itself, establish that a generating station caused transmission congestion. The charge should apply only where a transparent, verifiable methodology establishes that the entity's deviation caused or materially contributed to congestion in the relevant constrained element.

Further under Regulations 45(10)(b), of IEGC, 2023 following has been provided for Hydro Generating Stations

Quote

(b) During high inflow and water spillage conditions, the concerned RLDC shall allow scheduling of power from hydro generating stations for overload capability up to 10% of Installed Capacity or any other limit as per sub-clause (a) of this clause without the requirement of additional GNA for such overload capacity, subject to the availability of margins in the transmission system.

Unquote

The existing IEGC provision provides for scheduling hydro generation up to the permitted overload capability during high-inflow and spillage conditions, subject to transmission margins. NHPC requests that any congestion-charge methodology be applied consistently with this provision and the applicable RPC/RLDC directions. A blanket exemption based solely on season should not be assumed; the relevant facts, system instructions and causation should be assessed.

It is important that the proposed congestion charge should not result in duplicate recovery for the same deviation component where the Regional Entity has already been subjected to RTDA or another deviation-related charge under the applicable regulations. CERC may specify how the charges interact, including any distinct cost components that may lawfully be recovered separately.

The proposed Regulation should therefore clearly establish:

1. that congestion charge is distinct from, and should not result in duplication of, RTDA for the same underlying deviation;

2. that, where a deviation has already attracted RTDA or another deviation-related charge, the Commission's methodology should identify and prevent duplicate recovery of the same underlying component, while permitting a separate charge only where its distinct basis and incremental impact are demonstrated;

3. that congestion charges should be based on the **incremental contribution of the deviation to the congested transmission element**, rather than merely on the direction or magnitude of deviation; and

4. that deviations resulting from, or directly attributable to, valid System Operator instructions, transmission constraints, curtailment or other circumstances beyond the entity's reasonable control should be considered under an expressly defined and verifiable exclusion or adjustment mechanism;

It is therefore proposed that an appropriate proviso may be added to Regulation 30A(1)(a), as follows:

Quote

"Provided that the same deviation component shall not be recovered more than once under congestion charges and RTDA or another deviation-related charge. Any separate recovery shall require a distinct regulatory basis and shall be calculated so as to avoid duplicate recovery;

Provided further that an unforeseen, unplanned and verifiable forced outage, including one arising from abnormal high-silt or high-trash conditions, shall be assessed on the basis of causation, contemporaneous operating records and the applicable outage and scheduling provisions,

and shall not automatically attract congestion charges where the event did not cause or materially contribute to the identified congestion."

Unquote

Additional Comments

5 Amendment to Clause 1 of Regulation 25 – "Certificate of Successful Trial Run"

Hon'ble Commission in the draft second amendment has proposed to amend Regulation 21 (1) of CERC IEGC Regulation and reduce the period for notice of trial run from 7 days to 3 days as Hon'ble Commission is of the view that once the generating unit is ready for the trial operation, there is no reason to wait for 7 days for the trial run. This is a welcome step.

In the same background, NHPC would request Hon'ble Commission to amend Regulation 25(1) of the principal regulation. The existing Regulation 25(1) of CERC IEGC Regulation provides as under:

Quote

"(1) In case any objection is raised by a beneficiary in writing to the concerned RLDC with a copy to all concerned regarding the trial run within two (2) days of completion of such trial run, the concerned RLDC shall, within five (5) days of receipt of such objection, in coordination with the concerned entity and the beneficiaries, decide if the trial run was successful or if there is a need for a repeat trial run."

Unquote

Thus, in the present regulation, beneficiaries have been provided 2 days to raise objection on the trial run after which 5 days have been provided to RLDC to decide whether the trial run was successful or not. NHPC would request Hon'ble Commission to reduce these timelines as once the trial run has been conducted by the generating station, it is in the interest of the nation that the concerned unit is allowed to declare its Commercial Operation and schedule its power. In view of above, following amendment is proposed in Regulation 25(1) of CERC IEGC Regulations 2022:

Quote

"(1) In case any objection is raised by a beneficiary in writing to the concerned RLDC with a copy to all concerned regarding the trial run within **two (2) days** of completion of such trial run, the concerned RLDC shall, within **two (2) days** of receipt of such objection, in coordination with the concerned entity and the beneficiaries, decide if the trial run was successful or if there is a need for a repeat trial run."

Unquote

6 Amendment to Clause 9 of Regulation 34 – "System Restoration"

Clause 9 of Regulation 34 provides for compensation to an entity extending black start support by way of injection of power during system restoration. As per the existing provision, the supporting entity is paid for actual injection at 110% of the normal rate of charges for deviation in accordance with the DSM Regulations for the last block in which the grid was available.

Hydro generating stations have the inherent capability to provide black start support, which is essential for restoration of the grid following a grid failure. Hydro generating units are designed to self-start and provide the necessary electrical support for energisation and charging of associated transmission lines, thereby facilitating the sequential restoration of the transmission network and other generating stations.

The provision of such black start and line charging capability requires specific design features, equipment and associated electrical systems in a hydro generating station. Such capability has to be incorporated at the design and construction stage of the generating station and entails additional costs, besides associated operation, maintenance and periodic testing requirements. Consequently, the cost incurred for providing such capability gets reflected in the capital cost and, ultimately, in the Annual Fixed Cost (AFC) of the generating station over its useful life, which increase the tariff of hydro power plants.

At the same time, a grid failure requiring black start support is an exceptional and uncertain event and may occur only once or may not occur at all during the useful life of a generating station. Therefore, although the generating station incurs the additional cost of incorporating and retaining the black start and line charging capability throughout its useful life, the existing compensation mechanism under Clause 9 is triggered only when an actual system restoration event takes place and the entity actually injects power.

Thus, the existing mechanism primarily compensates the entity for actual black start support provided during a system restoration event, but does not adequately recognise

Aman Maheja

the availability of black start capability itself and the additional cost incurred by the generating station for providing such capability.

It is also pertinent to mention that the value of black start capability is not limited to the quantum of energy injected during a restoration event. The availability of a generating station capable of black start and line charging provides an important system-level benefit by enhancing grid resilience, reducing restoration time and facilitating faster and more orderly restoration of the grid following a major disturbance. The capability is therefore maintained for the benefit of the entire power system, even though the occasion for its actual utilisation may be rare.

Accordingly, there is a need to distinguish between:

(a) compensation for actual black start support/injection during system restoration, which is already provided under the existing Clause 9; and

(b) compensation for the additional cost and system-support value associated with having and demonstrating the requisite black start and line charging capability, irrespective of whether an actual grid restoration event occurs during the year.

It is therefore proposed that generating stations recognised for providing black start support may be provided an annual compensation for having and demonstrating the requisite black start capability. Such annual compensation may be linked to successful demonstration of the capability as required under Clause 3 of Regulation 34. This would ensure that the compensation is not merely a payment for an installed facility, but is linked to the continued availability and demonstrated readiness of the capability for system restoration.

Aman Mahajan

Considering the significant system benefit provided by such capability, it is proposed that the annual compensation may be provided at the following rates:

a. Rs. 2 lakh/MW per annum for generating stations having installed capacity up to and including 1000 MW; and

b. Rs. 1 lakh/MW per annum for generating stations having installed capacity exceeding 1000 MW.

The annual compensation may be shared between the generating station and its beneficiary DISCOMs in the ratio of 1:1 as the Annual Fixed Cost is recovered from the beneficiaries and it also provides a system-level benefit to the beneficiaries while the generating station incurs the additional capital and operational costs for providing and demonstrating such capability.

The annual compensation proposed above shall be in addition to the compensation payable for actual injection during a black start event under the existing provision of Clause 9. The two mechanisms serve different purposes: the annual compensation recognises the cost and availability of the black start capability, whereas the existing compensation recognises the actual support/injection provided during a system restoration event.

In view of the above, Clause 9 of Regulation 34 may be amended as follows:

Quote

"9) Any entity extending black start support by way of injection of power as identified in clause (6) of this Regulation shall be paid for actual injection @ 110% of the normal rate of charges for deviation in accordance with DSM Regulations

for the last block in which the grid was available. The procedure in this regard shall be prepared by NLDC in consultation with stakeholders and approved by the Commission.

Provided that an entity recognised for providing black start support and having the requisite black start and line charging capability, as demonstrated in accordance with clause (3) of this Regulation, shall be compensated annually at the rate of Rs. 2 lakh/MW per annum for generating stations having installed capacity up to and including 1000 MW and Rs. 1 lakh/MW per annum for generating stations having installed capacity exceeding 1000 MW."

Unquote

7 Amendment to Clause 1(b) of Annexure-4

Clause 1(b) of Annexure-4 provides for reactive power support charges at the rate of 5 paise/kVArh with effect from 01.10.2023, with an annual escalation of 0.5 paise/kVArh thereafter.

The existing provision regarding reactive-power compensation and VAr exchange pricing is intended to encourage regional entities to meet reactive-power requirements locally and minimise reactive-power drawal from the Inter-State Transmission System (ISTS), particularly under low-voltage conditions. Reactive power compensation plays a crucial role in maintaining voltage stability, power quality and grid reliability, particularly with the increasing integration of renewable energy sources such as solar and wind power. Large-scale renewable energy integration can result in voltage

fluctuations and increased reactive power management requirements, especially under weak grid conditions. Adequate reactive power support helps regulate voltage, reduce transmission losses, improve system reliability and facilitate higher penetration of renewable energy without adversely affecting grid performance.

The effectiveness of the existing rate and annual escalation should be reviewed against current costs, equipment investment, system conditions and the intended behavioural signal.

The annual escalation of 0.5 paise/kVArh may not, by itself, keep the charge aligned with changing costs or provide an adequate incentive for local reactive-power support. Any revision should be supported by a reasoned assessment of the cost of reactive-power provision, the impact on regional entities and the likely effect on voltage performance.

It is therefore suggested that the Commission review the base VArh charge and annual escalation using a transparent, cost-informed methodology, including the costs of providing reactive support and relevant system benefits, rather than adopting a rate without supporting analysis.

A properly calibrated VAr pricing mechanism could encourage regional entities to develop and effectively use local reactive-power compensation facilities, improve voltage profiles, reduce avoidable reactive-power flows and support grid security and reliability.

In view of the increasing importance of reactive power support for secure and reliable grid operation, it is proposed that the existing rate be reviewed against current costs, equipment investment, system conditions and the intended behavioural signal to provide adequate compensation for reactive power support services. Accordingly, Clause 1(b) of Annexure-4 may be amended as under:

Quote

"(b) The charge for VArh shall be at the rate of 25 paise/kVArh with effect from the date of coming into force of these Regulations. This rate shall be escalated at 2.5 paise/kVArh per year thereafter, unless otherwise revised."

Unquote

8 Amendment to Regulation 49(7)

Regulation 49 (7) of CERC IEGC Regulations 2023 provides as under:

Quote

Revision of Declared Capacity and schedule, shall be allowed on account of forced outage of a unit of a generating station or ESS (as an injecting entity) only in case of bilateral transactions and not in case of collective transaction. Such generating station or ESS (as injecting entity) or the electricity trader or any other agency selling power from the unit of the generating station or ESS shall immediately intimate the outage of the unit along with the requisition for revision of Declared Capacity and schedule and the estimated time of restoration of the unit, to SLDC or RLDC, as the case may be.

Unquote

The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised on pro-rata basis for all bilateral transactions. The revised Declared Capacity and schedules shall become effective from the time block and in the manner as specified in clause (4) of this Regulation:

Further the "Forced Outages has been defined in CERC IEGC Regulations 2023 as under:

Quote

3. DEFINITIONS

(55) Forced Outage means an outage of a generating unit or a transmission facility due to a fault or any other reasons which have not been planned;

Unquote

Hydro generating stations have operating characteristics that differ from those of thermal stations. Unplanned high-silt or high-trash events, extreme hydrological conditions and debris ingress may require immediate shutdown or reduction in generation to protect personnel and equipment. These conditions are site-specific and should be assessed on evidence rather than treated as automatic exemptions.

Regulation 3 of the CERC (Indian Electricity Grid Code) Regulations, 2023 defines "Forced Outage" as an outage of a generating unit or transmission facility due to a fault or other reasons which have not been planned.

The definition of "Forced Outage" in Regulation 3(55) refers to an outage due to a fault or other reason that was not planned. The existing definition is broad enough to encompass unplanned outages in hydroelectric generating stations arising from abnormal hydrological conditions, including high silt or trash concentrations, extreme

hydrological events and debris ingress, which may necessitate an immediate shutdown or reduction in generation to safeguard personnel and equipment. However, the interpretation and regulatory treatment of such events as Forced Outages are not uniform across different Regional Load Despatch Centres (RLDCs).

In the view of NHPC, the classification of an outage as a Forced Outage should be determined by whether the event was genuinely unplanned and unavoidable, rather than solely by whether its cause was attributable to the generating equipment or to external hydrological conditions. Such external conditions directly affect the safe and reliable operation of hydroelectric generating stations and may necessitate an immediate shutdown or restriction in generation, notwithstanding the absence of any fault in the generating equipment.

Accordingly, NHPC requests Hon'ble Commission to clarify that outages resulting from abnormal, unplanned and demonstrably unavoidable hydrological conditions such as high-silt or high-trash or debris ingress may be qualified as a forced outage for applicable purpose of IEGC Regulations, subject to prompt reporting, contemporaneous operating records, relevant silt/trash measurements wherever applicable, equipment / protection evidence and post-event verification by the concerned system operator.

In view of above, Hon'ble Commission is requested to modify the definition of Forced Outage as under:

Quote

(55) 'Forced Outage' means an outage of a generating unit or a transmission facility due to a fault or any other reasons which have not been planned, and shall include an outage of a generating unit of hydroelectric generating station arising from unplanned hydrological conditions.

Unquote

9 Amendment to Clause 7(a) of Regulation 49

Central Electricity Regulatory Commission (Indian Electricity Grid Code) (First Amendment) Regulations, 2024 introduced Clause (7-a) after Clause (7) of Regulation 49 of the Principal Regulations as under:

Quote

"(7-a) Revision of Declared Capacity and schedule of a generating station or ESS (as an injecting entity) shall be allowed only in case of bilateral transactions and not in case of collective transaction as per following details:

.....

(b) The generating station based on lignite, gas, or hydro generating station shall be allowed 6(six) revisions of Declared Capacity and schedule in a day subject to a maximum of 120 (One hundred twenty) revisions during a month, due to reasons such as a partial outage of the unit or water availability for hydro generating stations or fuel quality or variations in the supply of gas for gas generating stations or any other technical reason to be recorded in writing"

Unquote

Comments of NHPC on the draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026

Clause (7-a)(b) of Regulation 49, inserted by the CERC IEGC First Amendment Regulations, 2024, allows six revisions of Declared Capacity and schedule per day, subject to a maximum of 120 revisions in a month, for specified technical and operational reasons. NHPC requests a review of this limit for hydro stations with more than three generating units.

Hydro stations with more than four (4) units may experience independent changes in unit availability, water availability, reservoir inflows, partial outages, maintenance status and system-operator instructions. These changes may require timely, unit-wise revisions to reflect actual capability and reduce avoidable schedule deviations.

The availability and operating status of individual units can change independently. A suitable revision allowance should accommodate legitimate operational changes while retaining time-block cut-offs, accurate reporting and compliance with RLDC communication protocols.

NHPC has commissioned four units of the eight-units, 2,000 MW Subansiri Lower HE Project. For a large multi-unit station, the existing revision limit may be restrictive when several unit-wise changes occur in a day. NHPC should support this request with station records showing revision frequency, causes and scheduling impacts.

It is proposed that hydro generating stations having more than four generating units be permitted up to 12 revisions of Declared Capacity and schedule per day, subject to a maximum of 160 revisions per month, for recorded unit-wise availability, water-availability or other technical/operational reasons. Alternatively, CERC may consider a proportionate limit linked to the number of generating units, supported by operational data.

Aman Maheja

The proposed enhancement would improve the accuracy of unit-wise Declared Capacity and schedules and help reflect changes in actual generating capability. The increased limit should be accompanied by reason codes, records of each revision and periodic reporting so that the Commission can review whether the allowance is being used appropriately without compromising grid security.

Accordingly, CERC is requested to consider amending Clause (7-a)(b) of Regulation 49 as under:

Quote

(b) The generating station based on lignite, gas, or hydro generating station shall be allowed 6 (six) revisions of Declared Capacity and schedule in a day subject to a maximum of 120 (One hundred twenty) revisions during a month, due to reasons such as a partial outage of the unit or water availability for hydro generating stations or fuel quality or variations in the supply of gas for gas generating stations or any other technical reason to be recorded in writing:

Provided hydro generating stations having more than 4 units shall be allowed 12 (twelve) revisions of Declared Capacity and schedule in a day subject to a maximum of 160 (One hundred sixty) revisions during a month

Unquote

10 Introduction of sub-clause (z) after sub-clause (y) of Clause 11 of Regulation 30

Hydro generating Station with pondage or storage are expected to provide secondary control i.e. SRAS-Up and SRAS-Down support to the Grid as per Regulation 30(11)(b)

of CERC IEGC Regulations 2023. The commercial mechanism for settlement of Secondary response provided by regional entity has been detailed in CERC Ancillary Services Regulations 2022 notified on 31.01.2022.

However, NHPC is facing operational constraint for providing SRAS-Down Support especially during monsoon season as water is spilled during monsoon season and the ECR which is paid back to DSM and Ancillary Services Account is practically a penalty to hydro generating station.

This has also been highlighted by GRID India in its consultation paper dated 31.12.2025. In the consultation paper, GRID India discussed the operation of hydro power plants especially for AGC-Down (SRAS- Down) as under:

Quote

".....In the case of hydro stations, however, water is the conserved resource during down regulation. The difficulty arises because the ECR for hydro is only a notional value and does not capture the true economic value of stored water, especially in a system with high renewable penetration and peaking needs.

While hydro stations may attempt to utilize the "saved" water by increasing their Declared Capacity (DC) and generation on subsequent days, this is only practically feasible in lean hydro periods**, when reservoir and pondage levels are not full. **During high inflow/high hydro seasons, the DC and actual generation are already constrained by installed capacity and hydraulic limitations; they cannot be increased indefinitely to compensate for prior down regulation. As a result, down regulation is perceived as a net penalty by the hydro power plants,

effectively offsetting or even negating the SRAS incentives earned for AGC participation."

Unquote

NHPC therefore requests Hon'ble Commission that following sub-clause (z) after sub-clause (y) of Clause 11 of Regulation 30 as under:

Quote

(z) During high-inflow periods, the System Operator consider available water and spillage risk to hydro generating stations when issuing SRAS-Down instructions and, where system security permits, avoid instructions likely to cause avoidable spillage.

Provided that in case SRAS Down signal is unavoidable during high inflow season, the hydro generating stations may be exempted from payment of ECR to Deviation/ Ancillary Pool account corresponding to down energy in case there is spillage of water as established by the generating station.

Unquote

11 Charges for Injection of Infirm Power

CERC DSM (Second Amendment) Regulations, 2025 provides as under:

Quote

"(8) Charges for injection of infirm power -

(1) The charges for injection of infirm power shall be zero, except in cases specified under clauses (2) and (3) of this Regulation:

Unquote

Aman Mahajan

In this regard, NHPC submits that the DSM treatment of infirm power injected by hydro generating stations during authorised commissioning and testing requires specific consideration, having regard to the distinctive operational and hydrological characteristics of such stations.

Under the applicable provisions of the IEGC Regulations, demonstration of a successful trial run of a hydro generating unit requires operation in accordance with the prescribed technical parameters and duration. The successful completion of such trials may depend upon the availability of adequate and sustained inflows, which are often seasonal. Consequently, the commissioning schedule of a hydro generating unit may be materially affected by hydrological conditions, notwithstanding the technical readiness of the unit.

Under the existing regulatory framework, scheduling of power from a hydro generating unit prior to successful completion of its trial run is not permitted. However, subject to approval of the concerned RLDC, infirm power may be injected into the grid during this period, with such injection being accounted for as a deviation.

The CERC (Deviation Settlement Mechanism and Related Matters) Regulations, 2024 do not provide a specific rate for the settlement of such infirm power injected prior to the trial run.

This issue is particularly significant for hydro generating stations, where water availability is often seasonal and prolonged non-utilisation of available inflows may result in avoidable spillage for eg: the period between notice of trial run and commencement of trial run or period after trial run and successful declaration of trial

run. There may be instances when grid frequency is low and the grid could benefit from additional hydro generation, but the generating station shall not inject infirm power in the absence of a specified settlement rate, notwithstanding RLDC approval for such injection. This results in the loss of potential energy generation and inefficient utilisation of available water resources. Providing an appropriate settlement mechanism for such infirm power, subject to RLDC approval and grid security requirements, would facilitate better utilisation of available hydro resources without permitting scheduled commercial generation prior to successful completion of the trial run.

Further, in the case of hydro generating stations governed by Section 62 of the Electricity Act, 2003, any revenue earned from the sale or settlement of infirm power during the pre-trial-run period, if permitted under the applicable regulations, may be adjusted against the capital cost as per Regulation 6 of CERC Tariff Regulations 2024. Such adjustment would reduce the capital cost considered for tariff determination and, consequently, the tariff burden on beneficiaries. Thus, providing an appropriate rate for such infirm power would not only promote efficient utilisation of available water resources but also facilitate the sharing of the resulting financial benefits with the beneficiaries.

In view of the above, NHPC requests the Hon'ble Commission to provide a specific settlement mechanism under the DSM Regulations for infirm power injected by Section-62 hydro generating stations prior to successful completion of the trial run, subject to prior approval of the concerned RLDC, grid security requirements and other conditions prescribed by the Commission. The rate may be determined as a specified

percentage of the applicable normal rate of charges, subject to an appropriate ceiling linked to the daily average market price of electricity discovered on power exchanges, or such other methodology as the Hon'ble Commission may consider appropriate. The revenue so earned shall be accounted for in accordance with the applicable Tariff Regulations.



Annexure-I

Revised Appendix-I

Declared capacity of Central Hydro Generating Station (on D-1 day by 6 am)	% Share and quantum of allocation of free power share of State Govt.in Central Hydro Generating Station	Allocated share to the state (State DISCOMS)	Entitlement of State Government as free power for sale on D day	Power sold by the State Government in DAM on D-1 Day for D day	Injection schedule of Central Hydro Generating Station on D day to State DISCOMS	Total Scheduled generation of Central Hydro Generating Station at its bus on for sale on D day	Revised DC/ schedule by Central Hydro Generating Station due to any reason/ partial outage on D day	Revised entitlement of State Government as free power for sale on D day	Power already sold by the State Govt. in DAM	Revised Hydro Station Scheduled generation on D day to State Discoms	Total scheduled Generation for D day at Central Hydro Generating Station bus bar)	Actual generation by the Hydro Generating Station on D day	Purchase (+) / Sale (-) of power from the market by State Govt. on D day	Deviation at Bus	Deviation of Central Hydro Generating Station	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)	Remarks
(A)	(B)	(C = A - B)	(D = B)	(E)	(F)	(G = D + F)	(H)	(I)	(J = E)	(K = H - I)	(L = J+ K)	(M)	(N)	O=(M+N)-L	P=M-H	Q=(I+N)-J	
1000	120	880	120	120	880	1000	800	96	120	704	824	800	24	0	0	0	No deviation applicable
1000	120	880	120	120	880	1000	800	96	120	704	824	800	0	-24	0	-24	24 MW underdrawal by the State Government
1000	120	880	120	120	880	1000	1100	132	120	968	1088	1100	0	12	0	12	12 MW overdrawal by the State Government
1000	120	880	120	120	880	1000	1100	132	120	968	1088	1100	-12	0	0	0	No deviation applicable
1000	120	880	120	120	880	1000	500	60	120	440	560	450	60	-50	-50	0	50 MW under injection by the Hydro Generating Station
1000	120	880	120	120	880	1000	500	60	120	440	560	550	60	50	50	0	50 MW over injection by the Hydro Generating Station
1000	120	880	120	120	880	1000	500	60	120	440	560	500	0	-60	0	-60	60 MW underdrawal by the State Government
1000	120	880	120	120	880	1000	500	60	120	440	560	400	0	-160	-100	-60	100 MW under injection by the Hydro Generating Station 60 MW underdrawal by the State Government
1000	120	880	120	120	880	1000	500	60	120	440	560	550	0	-10	50	-60	50 MW over injection by the Hydro Generating Station 60 MW underdrawal by the State Government