MAHAVITARAN
Maharashtra State Electricity Distribution Co. Ltd.

(A Govt. of Maharashtra Undertaking)
CIN: U40109MH2005SGC153645

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Ref. No: CE/PM&T/IEGC/ No 3 5 8 0 9 **Date:** 21 OCT 2026

To,
The Secretary,
Central Electricity Regulatory Commission,
World Trade Centre,
6th, 7th and 8th Floor, Tower-B,
Nauroji Nagar, New Delhi – 110029.

Email: secy@cercind.gov.in; shilpa@cercind.gov.in

Subject: **Submission of comments on the Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026.**

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

Respected Sir,

With reference to the public notice cited above, MSEDCL hereby submits its comments and suggestions on the Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026, for kind consideration of the Hon'ble Commission.

At the outset, MSEDCL appreciates the Commission's initiative to shorten the timelines between scheduling revisions under Regulations 48 and 49 of the Grid Code. The proposed reduction in the time gap between successive revisions is a welcome step towards enabling market participants, particularly distribution licensees, to respond more effectively to changing demand and renewable energy generation closer to the time of actual consumption.

The proposed changes will facilitate better optimisation of power procurement portfolios by enabling Discoms to buy or sell power in the market closer to real-time requirements and reduce the risk of over-procurement or under-procurement. Further, the facility to revise schedules of ISGS stations at earlier time blocks—moving from the existing 7th/8th-block timelines towards the proposed 5th/6th-block timelines, as applicable under the proposed phased implementation—will improve operational flexibility and assist Discoms in managing demand and generation variations more accurately.

While appreciating these progressive measures, MSEDCL wishes to bring certain operational, technical and financial concerns arising from other proposed amendments to the kind attention of the Hon'ble Commission.

The detailed clause-wise comments, including the specific suggestions/proposed amendments and the rationale for each, are enclosed herewith for consideration of the Hon'ble Commission.

MSEDCL respectfully requests the Hon'ble Commission to kindly consider the enclosed comments and suggestions while finalising the Draft CERC (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026, so that the final provisions promote efficient market participation, secure and reliable grid operation, and a fair and transparent framework for distribution licensees and other stakeholders.

Thanking you.

Yours faithfully,

Chief Engineer
(Power Management &Trading)
MSEDCL

Copy s.w.rs. to :

1. Director (Commercial), Prakashgad, MSEDCL
2. Executive Director, (Commercial)
3. Executive Director, (Power Purchase)

Sub:- Draft comments on Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026.

Sr	Draft Provision	MSEDCL Suggestion / Concern	Rationale
1	Amendment to Regulation 19(3)(a)(iii) of the Principal Regulations: "RLDC may allow multiple extensions with a cumulative time extension for three months, after carefully examining the reasons for such extension."	It is suggested that the number of extensions permitted by the RLDC be restricted to a maximum of three, with the cumulative period of extension not exceeding three months. Accordingly, the provision may be suitably modified as follows: **"RLDC may allow a maximum of three extensions, with a cumulative time extension not exceeding three months, after carefully examining and recording the reasons for each such extension."**	The provision allowing multiple extensions without specifying a maximum number may lead to repeated requests for extensions, resulting in uncertainty regarding the actual Commercial Operation Date (COD) of generating stations and prolonged uncertainty in power availability and scheduling arrangements for procuring entities. Restricting the number of extensions to a maximum of three, while retaining the cumulative extension limit of three months, would promote timely project commissioning, enhance accountability of generating entities, and facilitate effective power procurement planning by distribution licensees. Further, requiring the RLDC to record the reasons for each extension would ensure greater transparency, accountability, and regulatory discipline in granting such extensions.
2	Amendment to Regulation 22(3)(a) of the Principal Regulations: "Provided also that in the case of a project having a capacity of 250 MW or more, the trial run may be performed in instalments, with a minimum capacity of 50 MW without any limit on the number of instalments."	It is suggested that the capacity considered for conducting the trial run of a Wind/Solar generating project shall be based on the aggregate AC capacity of the Wind Turbine/inverters. Further, for projects having a capacity of 250 MW or more, the trial run may be permitted in minimum instalments of 50 MW or multiples thereof, subject to a maximum number of instalments corresponding to the total project capacity, rather than allowing an unlimited	In renewable energy projects, the aggregate AC capacity of the inverters represents the capacity available for conversion and injection of power into the grid. Therefore, determining the trial-run capacity based on AC inverter capacity for Solar plant would ensure consistency between the capacity tested, grid injection capability, and the capacity considered for commercial operation. Further, allowing an unlimited number of instalments may result in fragmented commissioning and prolonged

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		number of instalments.	uncertainty regarding the commissioning of the complete project. Restricting the trial run to instalments of 50 MW or multiples thereof would facilitate systematic commissioning, effective monitoring by the RLDC, and timely declaration of COD for the project capacity.
3	5. Amendment to Regulation 22 of the Principal Regulations: (6) The following four provisos shall be added in sub-clause (e) of Clause (3) of Regulation 22 of the Principal Regulations. "Provided that the trial run of a standalone ESS shall be performed for a minimum capacity aggregating to 50 MW: Provided further that in the case of a standalone ESS having a capacity of more than 50 MW and less than 250 MW, the trial run for the balance capacity shall be performed in a maximum of three instalments with a minimum capacity of 5 MW: Provided also that the trial run for a standalone ESS aggregating to less than 50 MW covered under clause (e) or clause(f) of Regulation 4.1 or Regulation 4.4 of the GNA Regulations, shall be allowed for the capacity for which Connectivity has been granted to such an entity: Provided also that in the case of a project having a capacity of 250 MW or more, the	It is suggested that the provision allowing trial runs in instalments without any limit on their number may be revised. For standalone ESS projects having a capacity of 250 MW or more, the trial run should be conducted in minimum instalments of 50 MW or multiples thereof, with the number of instalments restricted in accordance with the total installed capacity of the project.	Permitting an unlimited number of instalments may lead to excessive fragmentation of the commissioning process and delays in achieving commercial operation of the entire ESS project. Specifying instalments of 50 MW or multiples thereof would ensure standardisation of trial-run capacity, facilitate effective monitoring by the RLDC, and enable systematic commissioning of the project. Restricting the number of instalments in proportion to the total project capacity would also promote timely commissioning and ensure that the trial-run process remains efficient and transparent.

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	trial run may be performed in instalments, with a minimum capacity of 50 MW without any limit on the number of instalments."		
4	5. Amendment to Regulation 22 of the Principal Regulations: (8) The following proviso shall be added in sub-clause (f) of Clause (3) of Regulation 22 of the Principal Regulations: "Provided that (i) short interruption or load reduction shall be permissible with the corresponding increase in duration of the test; (ii) interruption or partial loading may be allowed with the condition that the average load during the duration of the trial run shall not be less than MCR, excluding the period of interruption but including the corresponding extended period; (iii) cumulative interruption of more than four (4) hours (including both pumping and turbo-generator mode) shall call for a repeat of the trial run; (iv) If it is not possible to demonstrate the design capabilities at rated water drawing level due to insufficient reservoir levels, the COD may be declared, subject to the condition that same shall be demonstrated immediately when sufficient reservoir level is available after COD.	It is suggested that the provision should explicitly clarify the treatment of capacity charges in the event of de-rating of the unit capacity. The applicable capacity charges in case of de-rating shall be determined in accordance with the relevant provisions of the Power Purchase Agreement (PPA). In the absence of any specific provision in the PPA, the capacity charges shall be proportionately reduced with effect from the Commercial Operation Date (COD), based on the de-rated capacity. Any excess capacity charges recovered from the beneficiaries shall be refunded to the respective beneficiaries, along with Late Payment Surcharge (LPS) at the applicable rate, calculated from the date of such excess recovery until the date of refund.	In the event of de-rating, the generating unit would be capable of delivering power only up to its revised, de-rated capacity. Accordingly, recovery of capacity charges based on the original installed capacity, without accounting for the de-rating, may impose an unjustified financial burden on the beneficiaries. Providing for the determination of capacity charges in accordance with the PPA, and proportionate reduction in the absence of a specific contractual provision, would ensure that beneficiaries are charged appropriately for the capacity available. Further, refunding any excess capacity charges along with applicable LPS would compensate the beneficiaries for the period during which the excess amounts were retained by the generating company, thereby promoting financial discipline, transparency, and equitable treatment of all stakeholders.

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	Provided further that if such a pumped storage plant is not able to demonstrate the design capabilities at rated water drawing level when sufficient water is available, the pumped storage plant shall have the option to either go for a repeat trial run or de-rate the capacity. If the pumped storage plant decides to de-rate the unit capacity in terms of sub-clause (b) of Clause (2) of Regulation 22 of these Regulations, such de-rating shall be effective from the COD."		
5	6. Amendment to Regulation 24 of the Principal Regulations: (1) The words ", pumped storage plants having a capacity of more than 25 MW and ESS (excluding Pumped Storage Plant) having a capacity of 25 MW and above," shall be added after the words "hydro generating stations having a capacity of more than 25 MW" in Clause (2) of Regulation 24 of the Principal Regulations.	It is suggested that pumped storage plants (PSPs) contracted by distribution licensees to meet their peak power demand should be kept outside the ambit of Automatic Generation Control (AGC). The electrical energy required for pumping and charging such PSPs is generally arranged by the concerned distribution licensees based on their surplus power availability and power procurement economics. Utilisation of the stored energy for AGC services, particularly during periods when the distribution licensees require such power to meet their peak demand, may necessitate the procurement of replacement power from the market at higher rates. Accordingly, only those PSPs and Energy Storage Systems (ESS) specifically established or contracted exclusively for providing ancillary services should be subjected to AGC control by the National Load	PSPs require substantial electrical energy for pumping and charging, which is generally arranged by distribution licensees under their power procurement arrangements, based on anticipated demand, surplus power availability, and prevailing market prices. Utilisation of the stored energy for AGC services may affect the availability of such power to meet the distribution licensees' demand, particularly during peak demand periods, and may compel them to procure replacement power from the market at higher costs. Consequently, permitting such PSPs to participate in AGC without an appropriate compensation mechanism may result in distribution licensees bearing the cost of charging while the benefits and revenues from AGC services accrue elsewhere. Therefore, PSPs contracted by distribution licensees should preferably be excluded from AGC, except where they are specifically

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		Despatch Centre (NLDC) or the Regional Load Despatch Centre (RLDC), as applicable. However, if the Commission considers the participation of PSPs contracted by distribution licensees in AGC necessary in the interest of grid security and stability, it is suggested that 100% of the revenue or compensation attributable to the provision of AGC services by such PSPs be passed on to the concerned contracting distribution licensees that have arranged and borne the cost of the energy used for charging the PSPs.	intended for providing ancillary services. Alternatively, where AGC participation is considered necessary for grid security and stability, the entire revenue or compensation attributable to AGC services should be passed on to the concerned contracting distribution licensees. This would ensure equitable allocation of benefits, protect the commercial interests of distribution licensees, and avoid imposing an undue financial burden on them
6	7. Amendment to Regulation 25 of the Principal Regulations: (1) A new Regulation 25A shall be added after Regulation 25 of the Principal Regulations as under: "**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	**1. Clarification regarding scheduling of infirm power after successful trial run:** Sub-clause (1) of the proposed Regulation 25A should be suitably clarified to distinguish between infirm power injected after successful completion of the trial run and issuance of the requisite certificate, but prior to the declaration of COD, and power supplied after declaration of COD. The provision should also clarify that scheduling and commercial treatment of power after declaration of COD shall be governed by the applicable provisions of the Grid Code and the relevant PPA/contract. **2. Tariff for infirm power procured by the contracted buyer:** Sub-clause (3)(b) should be amended to provide that, where the buyer consents to procure infirm power prior to COD, such power shall be scheduled at the tariff mutually agreed between the buyer and the generating station or at	Successful completion of the trial run and issuance of the requisite certificate are important milestones in the commissioning process. However, these events do not, by themselves, necessarily signify the declaration of COD. A clear distinction between infirm power injected before COD and power supplied after COD is therefore necessary to ensure appropriate scheduling and commercial treatment in accordance with the applicable regulatory and contractual framework. Further, specifying that infirm power shall be procured at the mutually agreed tariff or the tariff stipulated in the applicable PPA/contract would provide contractual certainty and safeguard the interests of the buyers. In the case of ESS, charging energy constitutes a significant component of the cost of stored electricity. Where the contracted buyer declines to

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	Contract. (3) In the absence of any specific provisions of treatment of sale of power prior to achieving commercial operation under the contract: (a) such power shall be first offered to the buyers with whom the generating station or ESS has entered into a contract either directly or through REIA or intermediary procurer, with an advance notice of at least seven (7) days. (b) If the buyer(s) give their consent to procure such power, the same shall be scheduled to the buyer(s) at a tariff mutually agreed between buyer(s) and the generating station. (c) If the buyer(s) or the REIA or intermediary procurer do not respond within such notice period, it shall be considered as a deemed refusal of the buyer(s) or REIA or intermediary procurer and in such a case the generating station shall be free to sell such power to any of the third party outside the Contract.”	the tariff specified in the applicable PPA/contract, as the case may be. **3. Third-party sale and responsibility for arranging ESS charging power:** Sub-clause (3)(c) should explicitly provide that, in the case of an ESS, third-party sale of power outside the existing contract shall be permitted only where the energy required for charging the ESS is independently arranged by the ESS developer and does not utilise power contracted or procured by the distribution licensee. Further, the regulation should clearly specify that, where the contracted buyer does not consent to procure the infirm power intended to be stored in the ESS, the responsibility for arranging the charging energy shall rest with the ESS developer. Such charging energy shall not be arranged through the buyer's contracted power or through deviation settlement mechanisms (DSM), except to the extent expressly permitted under the applicable regulations. The Commission is requested to clarify the applicable arrangements for charging energy in the absence of a specific provision in the PPA/contract. It is further requested to prescribe the mechanism for procuring charging energy for an ESS (when the contracted buyer declines to purchase infirm power), including the applicable energy accounting, scheduling, and settlement arrangements. This would help avoid ambiguity	procure the infirm power, permitting the ESS developer to sell the stored energy to a third party without independently arranging the charging energy may result in the utilisation of power contracted or procured by the distribution licensee for the benefit of another party. This could impose an unintended financial burden on the distribution licensee. Accordingly, the responsibility for arranging charging energy should be clearly assigned to the ESS developer in such circumstances. Further, as the DSM framework is not permitting the use of deviation settlement arrangements for charging ESS/PSP beyond the purposes expressly allowed under the applicable regulations, the charging energy should be arranged through an expressly permitted mechanism. These clarifications would ensure transparent allocation of costs and responsibilities, protect the commercial interests of distribution licensees.

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		and potential disputes between the ESS developer and the distribution licensee	
7	10. Amendment to Regulation 30 the Principal Regulations: (4) Following news rows shall be added in Table 4, in sub-clause (h) of Clause (10) of Regulation 30 of the Principal Regulations as under: Pumped Storage Plant -25 MW and above -As per CEA Technical Standards for Connectivity Energy Storage System (except Pumped Storage Plant) -10 MW and connected at 33 kV and above - As per CEA Technical Standards for Connectivity"	It is suggested that Pumped Storage Plants (PSPs) and Energy Storage Systems (ESS) contracted with Discom should be kept outside the scope of mandatory primary frequency response requirements to the extent such response utilises capacity or energy contracted by distribution licensees for meeting their demand.	PSPs and ESS require charging energy, which may be arranged by distribution licensees through their contracted power procurement. Mandating primary frequency response from such facilities may reduce the capacity available for charging or discharging in accordance with the distribution licensees' requirements, resulting in underutilisation of the contracted capacity and potential financial burden on distribution licensees despite their obligation to pay 100% Capacity charges for the contracted power. Further, using contracted energy for grid-support services may create commercial complications relating to energy accounting, scheduling, availability and allocation of the benefits arising from such services. Accordingly, PSPs and ESS should be excluded from mandatory primary frequency response where it affects the capacity or energy committed to distribution licensees, unless a clearly defined compensation and settlement mechanism safeguards the interests of the concerned distribution licensees.
8	Amendment to Regulation 30 the Principal Regulations: (9) The words “or regional entity bulk consumer, as the case may be,” shall be inserted after the word “State” occurring multiple times in sub-clause (t) of Clause 11 of Regulation 30 of the principal Regulations. "	It is suggested that, in cases where such charges are attributable to a State, the charges should initially be allocated to the concerned State Load Despatch Centre (SLDC). The SLDC shall, in turn, de-pool and allocate the charges among the concerned entities within the State in accordance	Presently de-pooling RTDA charges for state is billed to MSEDCL by CTU though same pertain to state as a whole and there are multiple distribution licensees in Maharashtra. In spite of continuous followup with SLDC/STU these RTDA charges depooling is balance since Oct-2021 and

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		with a methodology consistent with CERC regulations and approved by the concerned State Electricity Regulatory Commission (SERC).	subsequently its amount has increased. Hence MSEDCL compel to pay RTDA to CTU. If such charges are allocated to SLDC then its depooling will done on priority by SLDC just like legacy charges. Hence Allocation of such charges through the SLDC would facilitate systematic settlement and appropriate apportionment among the entities responsible for the charges within the State. A clearly defined de-pooling methodology, consistent with CERC regulations and approved by the concerned SERC, would ensure transparency, regulatory oversight and equitable allocation of costs among the relevant entities, while avoiding ambiguity regarding the responsibility for payment of such charges.
9	Amendment to Regulation 30 the Principal Regulations: The words “, pumped storage plants having a capacity of more than 25 MW and ESS (excluding Pumped Storage Plant) having a capacity of 25 MW and above” shall be added after the words “hydro generating stations having a capacity of more than 25 MW” in sub-clause (w) of Clause (11) of Regulation 30 of the principal Regulations	It is suggested that Automatic Generation Control (AGC), if implemented for these facilities, should not be applied to PSPs and ESS to the extent their operation utilises energy procured or contracted by distribution licensees for charging. Alternatively, if their participation in AGC is considered necessary for grid security, an appropriate mechanism should be established to ensure that the distribution licensees are compensated for the utilisation of their contracted energy and that the capacity committed for meeting their demand is not adversely affected.	The energy required for charging PSPs and ESS may be arranged by distribution licensees through their existing power procurement contracts. Utilising such energy for AGC may affect the availability of stored energy and the charging/discharging schedule required to meet the distribution licensees' demand. This may result in underutilisation of contracted power, additional power procurement costs and commercial complications for distribution licensees. Accordingly, PSPs and ESS should be excluded from AGC where their participation affects energy or capacity contracted by distribution licensees, unless a suitable compensation and settlement

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			mechanism is prescribed to protect the financial and operational interests of the concerned distribution licensees.
10	**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 (b) Congestion charge to wheeling region in case of simultaneous congestion in import and export region: Where a control area/region simultaneously acts as an importing control area (downstream) with respect to one congested corridor and an exporting control area (upstream) with respect to another congested corridor (i.e. the control area/region is wheeling power and both its incoming and outgoing corridors are congested at the same time), any deviation from schedule by regional entities in that control area/region shall attract congestion charge irrespective of the direction or nature of the deviation and	It is suggested that, in cases where a control area or region experiences simultaneous congestion on its incoming and outgoing corridors, congestion charges should not be levied on regional entities in that control area solely on the basis of deviations from their respective schedules. Accordingly, Clause (1)(b) may be suitably modified to exempt such entities from congestion charges where their deviations cannot reasonably be established to have aggravated congestion on either corridor. Further, the same deviation should not attract both DSM charges and congestion charges unless a distinct and demonstrable basis for the additional levy is established. The levy of congestion charges should be guided by the **"causer pays" principle**, whereby charges are imposed on entities whose actions aggravate congestion, while entities that demonstrably relieve congestion are appropriately compensated.	The primary objective of congestion charges is to incentivise regional entities to take corrective actions that relieve congestion in inter-regional and intra-regional transmission corridors, thereby reducing the risk of overloading, tripping of transmission lines, and consequential cascading outages. Accordingly, congestion charges should be imposed on entities whose deviations aggravate congestion and should reward entities whose actions help relieve it. However, where a control area or region simultaneously experiences congestion on both its incoming and outgoing corridors, deviations by entities within that region may not necessarily aggravate congestion or contribute to its relief. Therefore, levying congestion charges on all entities in such a region, irrespective of the actual impact of their deviations on congestion, may not be consistent with the underlying objective of the proposed mechanism. Further, the proposed provision could effectively require distribution licensees in the affected region to maintain their drawal strictly in accordance with their schedules to avoid congestion charges, irrespective of the actual impact of their deviations on the congested corridors. In practice, maintaining

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	irrespective of whether the deviation apparently relieves or aggravates the congestion on a particular corridor. (c) The congestion charge shall be payable or receivable, as the case may be, in addition to the applicable deviation charges as per the DSM Regulations.		exact schedule adherence at all times is difficult for distribution licensees due to the dynamic nature of electricity demand, weather-related variations, fluctuations in net demand arising from distributed renewable energy (DRE) generation within the State Transmission Utility (STU) network, and limitations on time period required to revise drawal schedules. These factors may result in unavoidable deviations despite reasonable efforts in demand forecasting and scheduling. Consequently, imposing congestion charges in addition to the applicable DSM charges, without establishing that the deviation has independently aggravated congestion, could place an undue financial burden on distribution licensees. It is therefore suggested that congestion charges in cases of simultaneous congestion on incoming and outgoing corridors should be levied only where the responsible entity's contribution to aggravating congestion can be objectively established. This would ensure that the mechanism remains aligned with the “causer pays” principle, provides appropriate incentives for congestion relief, and avoids unjustified financial liability on distribution licensees for deviations that do not aggravate congestion.

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11	CONGESTION CHARGE (1) Applicability of Congestion Charge. (4) Notice for withdrawal of congestion charge. When in the opinion of the NLDC or RLDCs, flow of electricity on the affected transmission link or corridor has come down to the ATC, it may, after notice through voice or e-mail message and through posting on its website and the common screen available on the Energy Management System, withdraw the applicability of congestion charge from a particular time-block:	It is suggested that the RLDC shall make available real-time information on inter-regional transmission line/corridor flows, ATC, TTC and congestion status to distribution licensees through a common online platform or Energy Management System (EMS) interface. The information should be updated continuously or at the shortest technically feasible interval to enable distribution licensees to monitor congestion conditions and take timely operational decisions.	Real-time visibility of inter-regional transmission flows and congestion status is essential for distribution licensees to assess grid conditions, understand the applicability of congestion charges, and take appropriate measures for demand and power procurement management. In the absence of timely information, distribution licensees may not be able to ascertain the prevailing congestion conditions or anticipate the withdrawal of congestion charges. Providing such information through the common EMS interface would improve transparency, facilitate coordination between RLDCs and distribution licensees, and support informed operational decisions.
12	Amendment to Regulation 45 the Principal Regulations: (1) The words "including revision of already declared high inflow period, as required:" shall be added after the words "shall be notified by the respective RPC" in second proviso of sub-clause (a) of Clause (8) of Regulation 45 of the Principal Regulations. (2) A new proviso shall be added after the second proviso of sub-clause (a) of Clause (8) of Regulation 45 of the Principal Regulations as under: "Provided also that regional entity thermal generating stations shall not declare the declared capacity in the Peak hours less than	It is suggested that the exception permitting a reduction in Declared Capacity on account of a partial outage be deleted. A reduction in Declared Capacity during peak hours should be permitted only in cases of a **verified forced outage**. Further, the definition of peak hours for the purpose of this provision should appropriately account for the actual demand profile and solar generation pattern, rather than being determined solely by whether the recorded demand occurs during daytime or evening hours. Accordingly, the relevant peak and off-peak periods should be identified with due consideration of solar and non-	Thermal generating stations have been observed to declare partial outages during periods of high demand, citing reasons such as variations in coal quality, coal mill tripping and other technical constraints. Such declarations may result in a reduction in Declared Capacity during critical demand periods. However, it may be difficult for beneficiaries and even SLDC in real time to independently verify whether the stated reasons genuinely warrant a reduction in Declared Capacity, particularly where the claimed constraints relate to coal quality variations or other operational and technical issues. The retention of a broad exception for partial

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	declared capacity in the off-peak hours, other than in case of forced outage or partial outage, failing which declared capacity for such generating station for the purpose of fixed charges shall be taken as the lower of the two.”	solar hours and the prevailing demand pattern.	outages may, therefore, provide scope for reductions in Declared Capacity during peak demand periods without adequate verification, adversely affecting the availability of power to distribution licensees and potentially increasing their power procurement costs. It is further submitted that the demand profile of Maharashtra has evolved due to measures undertaken by MSEDCL, including the shifting of agricultural load to daytime hours and the promotion of solar generation at the distribution level. Consequently, daytime demand may, in certain circumstances, be comparable to or higher than evening or morning demand, even though solar generation is substantial during daytime hours and limited/zero during non-solar hours. Therefore, the highest recorded demand alone may not adequately represent the periods of greatest dependence on conventional thermal generation. In view of the above, it is necessary to distinguish between solar and non-solar periods while assessing the requirement for generation availability, with particular emphasis on ensuring adequate thermal generation availability during non-solar peak-demand periods, when solar generation is unavailable or significantly reduced.

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			Accordingly, the exception for partial outages should be removed, and any reduction in Declared Capacity during peak hours should be permitted only in cases of a verified forced outage. This measure would discourage unjustified reductions in Declared Capacity during critical demand periods, improve the availability of thermal generation for beneficiaries, promote operational discipline and safeguard the interests of distribution licensees, including MSEDCL, by mitigating the risk of additional power procurement costs.
13	Amendment to Regulation 45 the Principal Regulations: (16) Regulation of access to defaulting entities: (a) In case of non-payment of dues of the statutory charges viz DSM charge, congestion charge, reactive energy charge payable under applicable Regulations by the entities or in case of non-maintenance of payment security mechanism, after the default trigger date, the scheduling of electricity for the defaulting entity shall be regulated as follows:"	It is suggested that the scope of charges covered under this provision be explicitly expanded to include **Ancillary Services charges payable under the RRAS mechanism, charges payable under the National SCED Statement for MTL Support, and any other outstanding charges payable to the Regional Pool Account under the applicable CERC Regulations, orders and procedures**, in addition to DSM, congestion and reactive energy charges. Charges payable towards RLDC/NLDC fees and charges may be excluded from the scope of this provision, as appropriate. Non-payment of any such charges beyond the applicable due date should trigger regulation of access in accordance with the proposed provisions, subject to the applicable regulatory	Timely payment of all dues payable to the Regional Pool Account is essential to maintain financial discipline, ensure the smooth settlement of regional pool transactions and safeguard the interests of entities that discharge their payment obligations in a timely manner. Non-payment of charges arising under the RRAS mechanism, National SCED Statement for MTL Support, DSM, congestion, reactive energy and other applicable regional pool settlement mechanisms may lead to the accumulation of substantial outstanding dues and adversely affect the financial discipline of the power sector. Instances have been brought to the notice of the Western Regional Power Committee (WRPC) in its meetings wherein generating companies have defaulted on the payment of DSM charges. In certain

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		framework.	cases, insolvency proceedings before the National Company Law Tribunal (NCLT) have posed challenges in recovering the outstanding dues in full. Issues relating to non-payment of DSM charges, reactive energy charges, congestion charges, legacy dues and amounts payable under the National SCED Statement for MTL Support have also been deliberated upon in the WRPC forum. These instances highlight the need for a robust and effective regulatory mechanism to ensure timely recovery of dues payable by defaulting entities. Further, a consistent and effective enforcement mechanism is necessary to ensure equitable treatment of all entities and adherence to payment obligations under the applicable CERC Regulations, orders and procedures. In this regard, the proposed provision is a welcome step towards strengthening payment discipline in the power sector. However, its effectiveness would be enhanced by extending its applicability to all relevant outstanding charges payable to the Regional Pool Account, rather than limiting it to the specific categories of charges presently enumerated. It is also pertinent to note that mechanisms such as the PRAPTI portal have been introduced to facilitate monitoring and resolution of outstanding dues payable by distribution licensees to generating

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			companies. MSEDCL submits that payment discipline and enforcement of legitimate dues should be pursued consistently across all categories of entities. Accordingly, an effective mechanism should also be available to address defaults by generating companies in payment of statutory and other applicable charges payable to the Regional Pool Account. **In view of the above, it is recommended that the proposed provision be amended to cover all applicable charges payable to the Regional Pool Account, excluding RLDC/NLDC fees and charges as considered appropriate by the Commission, and that non-payment beyond the applicable due date trigger regulation of access in accordance with the prescribed procedure.** This would strengthen recovery of outstanding dues, promote financial discipline, ensure equitable treatment of all entities and protect the interests of beneficiaries and other stakeholders in the electricity sector.
14	(17) Scheduling of Free Power share of State Government from bus bar of Central Hydro Generating Station The State Government having free power share in Central Hydro Generating Station (CHGS) may sell their entitled share of free power directly from the bus bar of the such hydro generating station.	It is suggested that a similar provision be incorporated to permit scheduling of power from any Inter-State Generating Station (ISGS) connected to the Inter-State Transmission System (ISTS) for charging Energy Storage Systems (ESS) or Pumped Storage Plants (PSPs) connected to the ISTS, without the application of	Permitting direct scheduling of power from ISGS to ESS or PSP connected to the ISTS would facilitate efficient utilisation of available generation for energy storage and support grid balancing, renewable energy integration and peak demand management. Application of transmission losses to such transactions may result in a reduction in the

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	The scheduling, accounting, and deviation settlement for the sale of free power share in the Central Hydro Generating Stations from the bus bar of Generating Station by the State Government shall be as per the Procedure at Annexure 8 of these regulations.”	transmission losses for such scheduling. The scheduling, accounting and settlement of such transactions may be governed by a procedure specified by CERC.	energy available for charging and create avoidable commercial complications. Therefore, allowing such scheduling without transmission loss adjustment, along with a clearly defined accounting and settlement mechanism, would promote efficient utilisation of storage facilities and support optimal operation of the national grid.
15	Amendment to Regulation 46 the Principal Regulations: (1) New sub-clause (a-i) and (a-ii) shall be inserted after sub-clause (a) of Clause (4) of Regulation 46 of the Principal Regulations as under: “(a-i) The generating station shall, by 1430 Hrs of ‘D-1’ day, inform the RLDC and beneficiaries of the proposed unit(s) to be taken under USD.	**Suggestion 1: Treatment of Fixed Charges on URS Availed for Technical Minimum Support** It is suggested that CERC may provide for the following treatment of fixed charges where a beneficiary schedules Un-Requisitioned Surplus (URS) over and above its allocated share to enable a thermal generating unit to operate at its Technical Minimum (TM) and thereby avoid Reserve Shutdown (RSD): 1. Where the aggregate schedule of a generating unit would otherwise fall below its applicable TM level, a beneficiary may schedule additional URS to enable the unit to remain in service at or above TM. 2. The incremental URS quantum scheduled specifically to maintain the unit at TM and avoid RSD should not attract additional fixed charges on the beneficiary providing such support. The corresponding fixed-charge liability should continue to be	A beneficiary that schedules additional URS to maintain a generating unit in service at its TM level already bears the applicable energy charges for the additional power scheduled. Such scheduling also provides an operational benefit by avoiding an otherwise necessary RSD and keeping the generating unit available to meet subsequent increases in demand. Levying additional fixed charges on the beneficiary for the incremental URS quantum required solely to maintain the unit at TM may discourage beneficiaries from providing such support. This could lead to avoidable RSDs, followed by additional start-up costs, increased thermal and mechanical stress on generating units, and operational constraints associated with restarting the units. Keeping a thermal unit in service at TM also preserves its availability during subsequent peak-demand periods. This benefits not only the beneficiary providing the additional schedule but

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		allocated among the original beneficiaries in proportion to their respective shares, in accordance with the applicable tariff regulations. 3. Any URS scheduled beyond the quantum required to maintain the unit at TM should attract fixed charges in accordance with the applicable regulations. CERC may accordingly clarify the treatment of such URS in Regulation 46 and the relevant provisions governing recovery and allocation of fixed charges.	also the other beneficiaries, which may requisition power from the unit when their demand increases. Such availability may be particularly important during non-solar hours, when solar generation is unavailable or significantly reduced. In the absence of a specific provision, a beneficiary providing additional URS to maintain a unit at TM may be required to bear both the additional energy charges and fixed charges on the incremental quantum, while the original beneficiaries continue to bear fixed charges corresponding to their allocated shares. This may create a disincentive for providing operational support that benefits the generating station and its beneficiaries collectively. Accordingly, the incremental URS quantum required to maintain the unit at TM and avoid RSD should not attract additional fixed charges on the supporting beneficiary. The existing allocation of fixed charges among the original beneficiaries should remain unaffected, while fixed charges on any URS scheduled beyond the quantum required for TM support should continue to be governed by the applicable regulations. This would promote equitable cost allocation, encourage flexibility in scheduling and help avoid unnecessary shutdowns and start-ups of thermal generating units.

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Illustrative Example

Assume a thermal generating unit has a Declared Capacity (DC) of 100 MW and an applicable Technical Minimum of 55% of DC, i.e., 55 MW. The shares and schedules of three beneficiaries at 1830 hours on Day D-1 are as follows:

<table>
<tr><th>Particulars</th><th>B-1</th><th>B-2</th><th>B-3</th><th>Total</th></tr>
<tr><td>Allocated share (MW)</td><td>30</td><td>50</td><td>20</td><td>100</td></tr>
<tr><td>Schedule before additional TM support</td><td>15</td><td>0</td><td>10</td><td>25</td></tr>
<tr><td>Additional schedule for TM support (MW)</td><td>30</td><td>0</td><td>0</td><td>30</td></tr>
<tr><td>Revised schedule (MW)</td><td>45</td><td>0</td><td>10</td><td>55</td></tr>
</table>

Under the above circumstances:

1. The aggregate schedule of 25 MW is below the applicable TM of 55 MW. The generating station may, therefore, consider taking the unit under RSD, subject to the applicable regulations and operational requirements.
2. If B-1 schedules an additional 30 MW, the aggregate schedule increases to 55 MW, enabling the unit to remain in service at TM.
3. B-1's allocated share is 30 MW, whereas its
</td></tr>
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			revised schedule is 45 MW. Accordingly, 15 MW represents URS scheduled by B-1 over and above its allocated share. 4. Of the additional 30 MW scheduled by B-1, 15 MW brings its schedule up to its allocated share of 30 MW, while the remaining 15 MW constitutes URS beyond its share. The proposed relief from additional fixed charges should apply to this 15 MW quantum, provided it is established that the quantum is required to maintain the unit at TM and avoid RSD. 5. Any URS scheduled beyond the quantum required for TM support should attract fixed charges in accordance with the applicable regulations. This arrangement would enable the unit to remain available for subsequent peak-demand periods and allow other beneficiaries to schedule power from the unit as required, subject to applicable scheduling provisions
		Suggestion 2: Scheduling Discipline to Avoid Avoidable Reserve Shutdown of Thermal Units It is suggested that CERC may prescribe appropriate scheduling discipline for beneficiaries of thermal generating stations to minimise avoidable RSD of generating units arising from	It has been observed that certain beneficiaries schedule little or no power from thermal generating stations during solar hours and substantially increase their requisition to full schedule during evening or other peak-demand periods . While such scheduling patterns may help the concerned beneficiaries reduce their power procurement costs by taking advantage

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		intermittent or highly variable requisition patterns. In this regard, the following alternatives may be considered: **Option A — Minimum scheduling requirement following a zero schedule** Where a beneficiary schedules zero power from a generating unit in any time block, its schedule for the remaining time blocks of the day may be treated as zero, except where a scheduling pattern has been declared in advance and is permitted under the applicable scheduling framework, provided that the aggregate schedule of the generating station remains at or above the applicable TM level. **Option B — Minimum schedule across time blocks** Alternatively, where a beneficiary intends to schedule power from a thermal generating station during peak-demand periods, it may be required to maintain a prescribed minimum schedule say 30% of its allocated share by MoP during the remaining time blocks, including solar hours, to the extent necessary to prevent the aggregate schedule of the unit from falling below TM. The precise	of solar generation, they may also cause the aggregate schedule of a thermal generating unit to fall below its TM level during daytime hours. Where the aggregate schedule falls below TM, the generating station may be required to take the unit under RSD. Such a shutdown may result in additional start-up costs, increased equipment stress, operational constraints and reduced availability of the unit during subsequent peak-demand periods. Furthermore, beneficiaries that maintain their schedules more consistently may effectively bear the operational consequences of variable requisition patterns adopted by other beneficiaries. This may create an inequitable situation in which the scheduling decisions of one beneficiary adversely affect the availability of generation for all beneficiaries of the station. Prescribing an appropriate minimum scheduling requirement, where necessary to maintain the unit at TM, would encourage greater coordination among beneficiaries and help minimise avoidable RSDs. It would also preserve thermal generation availability during peak-demand and non-solar periods, thereby supporting grid reliability and reducing avoidable shutdown and start-up costs.

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		methodology may be prescribed by CERC after considering the operational requirements of the generating station and the scheduling obligations of its beneficiaries. The above safeguards should apply only where the aggregate schedule would otherwise fall below the applicable TM and result in an avoidable RSD. They should not interfere with merit-order dispatch or otherwise restrict legitimate scheduling variations in accordance with the applicable regulations.	Accordingly, CERC may consider introducing a suitable scheduling discipline that requires beneficiaries intending to schedule power during peak-demand periods to maintain a minimum schedule during other relevant time blocks, wherever necessary to ensure that the aggregate schedule of the generating unit does not fall below TM. The requirement should be proportionate, objectively defined and subject to appropriate exceptions so that it addresses avoidable RSD without unduly restricting beneficiaries' legitimate scheduling flexibility or interfering with merit-order dispatch.