serentica

Ref: SRIPL/CERC/2025/10/17 Date: 17.10.2025

To
The Secretary
Central Electricity Regulatory Commission
Tower B, 6,7,8 Floor, World Trade Centre,
Safdarjung Enclave, New Delhi - 110029

Subject: Comments on CERC Petition No. 9/SM/2025 (Suo Moto) on determination of the value of 'X' under the under the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2024.

Dear Sir

The Central Electricity Regulatory Commission (CERC), in Petition No. 9/SM/2025 (Suo Moto), has proposed a methodology for determining the value of "X" for computing the deviation percentage for wind and solar (WS) sellers, applicable from April 1, 2026, under the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2024.

The proposal suggests a staggered reduction of the "X" factor from 100% in FY 2027 to 20% in FY 2031, and 0% thereafter. We present below our observations and recommendations on the proposed approach.

1. **Impact on Revenues of Renewable Energy Generators**
   According to the proposal, the "X" factor would lead to the following revenue losses for renewable energy (RE) generators. The analysis is based on a 41-week study (Sept 16, 2024 – June 29, 2025), covering 16 RE plants—solar, wind, and hybrid—across the Northern, Western, and Southern regions with varying forecasting accuracies.

Sr. No	Project Type	Range of Revenue loss for X -100% and 0%
1	Solar	-3.5% to -11.1%
2	Wind	-2.8% to -48.2 %
3	Hybrid	-2.4% to -11.8%

Each 1% reduction in topline revenue lowers the Project IRR by approximately 0.5%. Currently, projects are being developed with IRRs of 14–15% (under Section 63 PPAs) and 17–18% (for C&I PPAs). DSM loss assumptions in these PPAs range between 0.75% for Solar/Hybrid and 1.5% for Wind. However, if revenue losses reach 11% (Solar/Hybrid) and 48% (Wind), the corresponding IRR erosion would be around 5.5% and 24% respectively, resulting in IRRs that fall below the cost of capital[1] or even turn negative. This would severely damage the economic viability of RE projects, leading to large-scale closures—essentially "throwing the baby out with the bathwater".

While the proposed mitigation via aggregation of schedules offers some relief (at pooling substation level), it does not sufficiently prevent IRR erosion. For instance, even with DSM within 10.95%, the erosion is around 5.5%; when X = 80%, it falls to 2.45%, but further reductions in X (40% or 20%) would exacerbate Project IRR losses.

The recent regulatory narrowing of deviation bands—from ±15% to ±10% for wind and ±10% to ±5% for solar—has already triggered 2.5% – 3% revenue impact for ISTS-connected RE projects. The proposed "X" factor would compound this burden, nearly doubling DSM exposure and threatening project viability.

2. **Limitations of the Study**

We note that the study employs a limited sample of 16 RE projects—all under Section 63 PPAs. It does not capture the impact on C&I supply projects, particularly wind, where DSM is linked to the integrated ACP instead of contract price. This linkage could amplify DSM-related revenue erosion by 40–50%, especially for wind given that night-time ACP values can reach ₹10/kWh.

Additionally, **the sample size is too small to represent national dynamics**—just 1610 MW solar aggregated and 177.53 MW of wind aggregated for study, against India's installed capacities of 52 GW (wind) and 125 GW (solar) as of June 30, 2025. Given that around 45 GW of renewable energy is ISTS connected with nearly 35GW solar and 15 GW wind/hybrid, a 10% sample size—around 3.5 GW solar and 1.5 GW wind—would provide more robust conclusions.

It is important to acknowledge that systemic challenges in forecasting infrastructure remain unresolved. Indian weather models—such as the NCUM-R (NCMRWF Unified Model – Regional) and IMD's GFS-based models—operate at spatial resolutions of approximately 4 km, which, while advanced, are insufficient to capture hyperlocal cloud dynamics. Sudden cloud formation, dissipation, and movement—especially convective clouds—can occur at sub-kilometre scales and evolve within minutes. These events are typically unresolvable

[1] *Debt: Equity ratio = 75:25; Cost of Debt = 10%, Cost of Equity = 14%; WACC = (75%x10% + 25%x14%) = 7.5% + 3.5% = 11% (approx.)*

by satellite imagery or coarse-grid numerical models and are not reflected in schedule revisions due to gate closure constraints.

Such cloud events can drastically alter solar irradiance, leading to sharp generation drops or spikes within a single 15-minute block. The awaited CEA report on forecasting efficacy is expected to address these limitations. Until such improvements are implemented, introducing additional penalty-linked mechanisms like the "X" factor may be premature and could inadvertently penalize generators for deviations driven by atmospheric phenomena beyond their control.

Multiple statutory and expert institutions—including CEA, MNRE, IMD, and REMCs—have acknowledged the persistent limitations in forecasting accuracy for wind generation. IMD's Vision-2047 report and CEA's July 2025 AWS Guidelines both highlight the need for improved high-resolution models and localized meteorological data. Forecasting errors, often stemming from interpolated data and insufficient sensor coverage, continue to result in DSM penalties despite generators' best efforts. The shift from 'available capacity' to 'scheduled generation' in the DSM formula, and the proposed reduction of the "X" factor, fails to account for these systemic constraints. Moreover, Grid-India's 41-week simulation study (Sept 2024–June 2025) does not capture full seasonal variability, making its conclusions on forecasting improvement statistically limited.

Equating wind and solar generators with conventional sellers under a uniform DSM formula overlooks their inherent variability and forecasting limitations, is unfair and uncalled for. Institutions like CEA, MNRE, and IMD have acknowledged persistent gaps in forecasting accuracy. Without corresponding infrastructure improvements, reducing the "X" factor risks penalizing RE generators for deviations beyond their control.

3. Suggestions for Better RE Integration

While we principally oppose the concept of 'X-factor', till the aforementioned forecasting challenges are addressed, in the larger interest of grid and renewable energy, we have the following suggestions to make:

i. Regional-Level Aggregation of Schedules

Aggregation should be implemented at the regional grid level instead of merely at pooling substations. This approach aligns with the IEGC, 2023 framework and should build upon learnings from substation-level aggregation. Voltage-based regional aggregation—by grouping generators connected at 220 kV, 400 kV, or 765 kV—can help significantly reduce forecasting errors and improve RE integration.

ii. Market Mechanism for Managing RE Imbalances

Introduce, via regulation, a market for settling generation imbalances arising from weather-based forecasting errors, similar to Germany's EPEX-SPOT balancing

market. In Germany, the Balance Responsible Party (BRP)[2] aggregates generators, manages deviations, and settles them financially in the spot market. Deviations due to over- or under-generation can be addressed within 5 minutes, with settlement in immediate next time block, ensuring grid stability and fair compensation through market pricing. Over injection is sold in market and money received by RE generator, under injection triggers balancing energy paid by RE generator at the balancing price[3].

In contrast, India's real-time market opens one hour before delivery, which is too late for managing short-term renewable deviations. Further, under-injections must be addressed through strengthening ancillary markets—particularly primary and secondary reserve services, which is still evolving in India.

Under the earlier DSM framework, schedule revisions were permitted until the 4th time block prior to delivery, offering generators a degree of flexibility to respond to evolving weather conditions. In the current regime, however, schedules are effectively locked by the 7th or 8th time block, which translates to a lead time of approximately 1.75 to 2 hours. This extended lock-in period limits the ability of RE generators to adjust for intra-block variability—particularly short-duration cloud events that can significantly impact generation within a single 15-minute interval. In this context, a market-based mechanism for managing real-time imbalances would be more aligned with the operational characteristics of renewable energy, offering a constructive alternative to purely penalty-driven approaches.

iii. Battery Storage at the Regional Grid Level

Establish large-scale battery banks in RE-rich regions/substations to provide instantaneous MW balancing—absorbing over-generation and supporting under-generation. This centralized model, coordinated by RLDC/NLDC, would complement ongoing decentralized battery initiatives by RE developers. Such installations should be tendered akin to STATCOM (MVAR) systems under transmission TBCB guidelines.

The cost could be shared among DICs benefiting from grid stability, reduced to the extent of net balance from RE generators that could pay (under injection) or receive compensation (over injection) during deviations (for stored or drawn power). This

[2] ***Balance Responsible Party (BRP)*** *is the entity (or contract party) that manages each balancing group. The BRP is responsible for forecasting, schedule nomination and balancing deviations. It aggregates and manages multiple Renewable Generators/ load in Germany, and financially settles deviations in spot market on their behalf. It is mandatory for RE generator to be part of a balancing group;*

[3] *This is the* ***price used to settle imbalances*** *(i.e., deviations) between the scheduled and actual energy balance of each* ***Balancing Responsible Party (BRP)****. This price known is reBAP (Uniform Balancing Energy Price across Control Areas. reBAP = Sum of activated balancing energy (MWh)Sum of costs of activated balancing energy (€/MWh);*

approach would narrow deviation bands to parity levels with conventional generators, improving grid safety and reliability.

The "X" factor introduces a material shift in the commercial framework of existing PPAs and must be recognized as a "Change in Law" event. Alternatively, we strongly urge its complete withdrawal until supporting infrastructure—balancing markets, storage, and forecasting accuracy—is demonstrably in place.

4. **Revised Values of 'X'**

It is requested that 'X' be kept 100% for atleast the first 2-3 years to implement suggestions mentioned above on balancing market, storage, forecasting accuracy etc and post sufficient experience revised trajectory be suggested. This will ensure a graded way of transitioning ensuring RE integration and grid stability.

Looking forward to favourable consideration from your end.

Yours faithfully
For Serentica Renewable India Pvt. Ltd.



Kunal L Kaistha
Vice President – Regulatory & Advocacy