एनटीपीसी NTPC
A Maharatna Company

एन टी पी सी लिमिटेड
(भारत सरकार का उद्यम)
NTPC Limited
(A Govt. of India Enterprise)

केन्द्रीय कार्यालय / Corporate Centre

Date: 21.10.2026

The Secretary
Central Electricity Regulatory Commission,
7th floor, Tower-B, World Trade Centre
Nauroji Nagar, New Delhi-110029

Subject: NTPC Submissions on Draft CERC (Indian Electricity Grid Code) (Second Amendment) Regulations, 2026

Sir,

Hon'ble Commission has published Draft CERC (Indian Electricity Grid Code) (Second Amendment) Regulations 2026 on 21.09.2026 and has invited comments from the stakeholders on the Draft Regulations.

In this regard, please find enclosed submissions of NTPC on the Draft CERC (Indian Electricity Grid Code) (Second Amendment) Regulations 2026.

Thanking you,

Yours sincerely

Ajay Dua
ED (Commercial)

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NTPC Submissions on Draft CERC (IEGC) (Second Amendment) Regulations 2026

1. **Simplification of the proposed multiple sequential steps for beneficiaries, generating stations and NLDC before SCUC and USD.**

The draft amendment has proposed multiple sequential steps before SCUC and USD as under

Regulation 46(4)

……..

(a) By 1400 Hrs of D-1 day, 'D' being the day of delivery, NLDC in coordination with RLDCs shall publish a tentative list of generating stations or units thereof, which are likely to be scheduled below the minimum turndown level of the respective stations for some or all the time blocks of the D day, based on beneficiary requisitions and initial unconstrained bid results of DAM in the power exchanges, received till 1300 Hrs of the D-1 day.

"(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.

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

"(b) The revised requisition from the said generating stations, once confirmed by the beneficiaries by 1530 Hrs of D-1 day, shall be final and binding after 1530 Hrs of D-1 day and further reduction in drawal schedule shall not be allowed from such stations except in cases when the generating stations remain above minimum turn-down level."

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

(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.

(d) If the NLDC in coordination with the RLDCs, after considering the bid results as finalized and available from DAM-AS, anticipates shortfall of reserves in D day due to (i) extreme variation in weather conditions; (ii) high load forecast; (iii) the requirement of maintaining reserves on regional or all India basis for grid security; (iv) network congestion, NLDC may schedule incremental energy from the generating units in the list referred to in sub-clause (c) of this clause , so as to bring such units to their minimum turndown level in order to maximize availability of on-bar units, by 1700 Hrs. of D-1 day and update the list on the respective RLDC website:

……."

Submission:

(i). Eligibility Threshold for USD: The Regulation 46(4)(b)(i) of the draft proposes USD only when an entity is scheduled below 50% of its MCR, which renders units with schedules in the 50–55% range ineligible for USD. However, the CEA Flexible Operation Regulations-2023 and the IEGC 2023 stipulate a technical minimum level of 55% of MCR. Operating at schedules lower than 55% forces uncontrollable grid injection, thereby posing risks to grid stability and resulting in DSM implications for generators.

It is therefore proposed that the threshold for USD eligibility be revised to a schedule below 55% of unit capacity for units not committed under SCUC.

(ii). Simplification of SCUC/USD timelines: Instead multiple sequential steps for beneficiaries, generating stations and NLDC and to eliminate duplication in the existing process while providing a clear and time-bound sequence for finalization of schedules, implementation of SCUC and declaration of USD, the process timeline may be simplified without altering the intent of provisions 46(4) (a) and (b) may be modified and (d-i) may be inserted as suggested after Sr no-(iii) below.

(iii). Upward revisions after publication of SCUC list: To encourage more realistic schedules before SCUC exercise, a restriction may be imposed on upward revision in schedule from generating stations which have below MTL schedules but not identified for SCUC support.

Allowing unrestricted upward revisions after publication of SCUC list may alter the demand-supply position based on which the SCUC requirement was assessed and thereby dilute the effectiveness and intended objective of the SCUC mechanism. Therefore, a proviso in this regard may be inserted in Regulation 46(4)(d). Notably, such provision is in line with the provision for revision of DC by generating stations in case of partial outage.

In view of above three submissions, Regulation 46(4) (a), (b) and (d) may be modified and 46(4) (d-i) may be inserted to incorporate the simplified timelines.

Regulation 46(4)

……

*(a) By **1500 Hrs of D-1 day,** 'D' being the day of delivery, NLDC in coordination with RLDCs shall publish a tentative list of generating stations or units thereof, which are likely to be scheduled below the minimum turndown level of the respective stations for some or all the time blocks of the D day, based on beneficiary requisitions and initial unconstrained bid results of DAM in the power exchanges, received till 14:30Hrs of the D-1 day.*

(a-i) The beneficiaries may revise schedules by 1630 Hrs of 'D-1' day to retain such units on-bar by ensuring scheduling of at least 55% MCR for all time blocks.

*(b) The revised requisition from the said generating stations, once confirmed by the beneficiaries by **1630 Hrs of D-1 day,** shall be final and binding after 1630 Hrs of D-1 day and further reduction*

in drawal schedule shall not be allowed from such stations except in cases when the generating stations remain above minimum turn-down level.

(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.

(d) If the NLDC in coordination with the RLDCs, after considering the bid results as finalized and available from DAM-AS, anticipates shortfall of reserves in D day due to (i) extreme variation in weather conditions; (ii) high load forecast; (iii) the requirement of maintaining reserves on regional or all India basis for grid security; (iv) network congestion, NLDC may schedule incremental energy from the generating units in the list referred to in sub-clause (c) of this clause , so as to bring such units to their minimum turndown level in order to maximize availability of on-bar units, by 1700 Hrs. of D-1 day and update the list on the respective RLDC website:

"Provided that in respect of such generating stations which are not identified for SCUC support, upward revision by beneficiaries may be permitted after publication of SCUC list only in exceptional circumstances, such as tripping of another generating unit, outage of a transmission element or any other technical reason to be recorded in writing, subject to an appropriate ceiling on the number of such upward revisions in a month by a particular beneficiary as per the detailed procedure of SCUC,USD and SCED."

Provided that in respect of such generating station or unit thereof which has been brought to its minimum turndown level by the NLDC under this clause, downward revision by the beneficiary shall not be allowed."

(d-i). The generating station may declare units under USD by 1800 Hrs of 'D-1' day if the schedule of at least 55% of MCR in all time blocks is not achieved."

(iv) Regulation 47(2)(c) may also be revised to increase the eligibility threshold for USD from 50% to 55% as below:

*"In case the generating station decides not to take unit(s) under USD, despite getting a schedule below **55% of MCR** for some or all time block(s) in a day, the requisitioned schedules shall not undergo any change under Clause (2) of this Regulation."*

2. **Minimum Off-Take obligation on Beneficiaries:**

Presently there is no minimum offtake obligation on the beneficiaries to provide technically feasible schedule to thermal stations. Consequently, many thermal stations receive below technical minimum or zero schedules during solar hours but are requisitioned fully during non-solar hours, despite the fact that technical minimum schedule is a foremost requirement for sustainable operation of thermal generating stations as a thermal station cannot operate below technical minimum level.

Though the responsibility for providing an operationally feasible schedule should lie with the beneficiaries, such stations are largely dependent on the technical minimum support provided by NLDC through SCUC and SCED-MTL support. However, as only a limited number of stations participate in SCUC/SCED (out of which majority are NTPC stations), the availability of down reserve remains constrained. As a result, stations are frequently undergoing USD and startup, leading to accelerated wear and tear of thermal assets and risk to grid stability.

It is worth mentioning that the CEA Committee report on "Evolving a mechanism for ensuring thermal generation at technical minimum" dated 30.06.2025 and NLDC's Petition No. 713/MP/2025 has also recommended for offtake obligation on beneficiaries.

In view of the above, it is requested to introduce minimum off-take obligation on beneficiaries to provide technical minimum schedules during solar hours if availing power during non-solar hours.

3. **Refinements to the Unit Shut Down (USD) Framework for Thermal Stations:**

(a) **MTL support/USD provision for units being revived from planned/forced outages:** Thermal units being revived from planned or forced outages currently face uncertainty regarding MTL support post-synchronization, risking economically unviable operation.

It is proposed that units being revived from planned or forced outage may be permitted to declare Off-Bar DC upon attaining readiness for revival, to indicate their availability for synchronization and dispatch. Such units may thereafter be brought on bar in accordance with the provisions applicable to USD units.

(b) **Specifying minimum off-bar and on-bar duration for USD:** The absence of a specified minimum off-bar/on-bar duration for units taken under USD in IEGC-2023 subjects thermal units to frequent start-stop cycles, leading to accelerated thermal and mechanical fatigue.

To mitigate these stresses and improve equipment life, it is requested to introduce a minimum off-bar duration of **one week** for units taken under USD and a minimum on-bar duration of **one week** upon revival.

(c) Recovery of costs associated with USD: During a USD, generators incur costs to run essential auxiliaries for safety and operational readiness. If a complete station goes under USD, it incurs transmission charges for drawing auxiliary power from the grid, along with secondary fuel oil consumption costs during start-up. Dur to rapid integration of renewable energy in the grid, instances of USD have increased considerably over the past few years, leading to substantial increase in the above-mentioned expenses related to USD of thermal stations or units thereof.

As these expenses are not recoverable under the extant tariff framework, it is proposed to introduce suitable provision in IEGC 2023 to ensure the recovery of APC costs, associated transmission charges, and start-up oil costs as a separate system service cost irrespective of the existing 7 start-up threshold in Regulation 70(G)(6) of CERC Tariff Regulations.

(d) Avoiding repetitive USD of same thermal units: As mentioned above, frequent start-stop operation of thermal generating units imposes significant thermal and mechanical stress on critical equipment, adversely affecting their health, reliability and long-term operational performance. The impact becomes even more pronounced when the same units are repeatedly selected for USD and revived within short intervals.

It is proposed that the selection of units for USD (not considered for SCUC support) may be done in consultation with the generator, thereby preventing disproportionate stress on specific units.

(e) SCUC support for at least one unit to avoid complete station shutdown: When a thermal station is not considered for SCUC support and beneficiary schedules cannot sustain even a single unit, all units of a thermal station need to be taken under USD, resulting in complete shutdown of the station. **Reviving a completely shut-down station is highly challenging and requires significantly higher time for revival due to restoration of common auxiliaries and balance-of-plant systems.**

To avoid these operational challenges, it is proposed that SCUC support equivalent to MTL of one unit may be ensured for stations not considered under SCUC.

(f) Revision in startup timelines for supercritical units: SCUC procedure dated 16.04.2024 (clause 6.12) provides revival times of 4, 8, and 12 hours for hot, warm, and cold start-ups respectively. However, supercritical units inherently require longer start-up durations compared to subcritical units due to stringent chemical parameter requirements. Supercritical units require a cold clean-up of condensate and feedwater of around 12 hours prior to boiler light-up, followed by a hot clean-up of 12 hours, resulting in an additional 24 hours for cold start-up, while warm start-up requires an additional 7–8 hours.

Accordingly, it is proposed that the norms for start-up time for super-critical thermal units be revised to 15 hours for warm start-up and 36 hours for cold start-up.

4. **Provision of Off-bar DC in case of Decommitment of unit:**

Regulation 46(6) of the draft has provided that NLDC may run SCUC at any time of the day to commit or decommit a unit for managing the grid security. In case of decommitting a unit or station thereof, the schedules of such station or unit shall be adjusted as per the Procedure under Annexure-9.

Submission:

Though the provision for decommitment has been incorporated, the off-bar DC and treatment of capacity charges in such cases has not been expressly specified. However, it is understood that a generating station decommitted to meet grid requirements shall remain eligible for recovery of capacity charges.

it is submitted that, to avoid any ambiguity, the provision of off-bar DC and payment of capacity charges in case of decommitment may also be specified in the regulations.

In view of the above, Sr no 4 (d) may be inserted in Annexure-9 as below:

"4(d). Once unit(s) of a generating station is decommitted, such generating station shall revise the On-bar DC (with due consideration to ramp up/down capability) and off-bar DC. The beneficiaries shall continue to bear the capacity charge corresponding to Total DC, including off-bar DC. The schedules for the day of scheduling 'D' day shall only correspond to on-bar unit(s)."

5. **Adjustment of schedule of energy cleared under DAM in case of USD:**

The draft proposes to insert Regulation 47 (2) (b) the Principal Regulations in case of a unit is taken under USD:

"(b). In case total requisitioned power cannot be supplied through other units in the same generating station on bar, the requisition from the beneficiaries shall be reduced in the ratio of requisitioned power."

Submission:

As per LPSC Rules, generators are required to offer the un-requisitioned power in day ahead market including units under USD. In case a generating station takes an on-bar unit under USD, while beneficiary schedules are reduced in the ratio of their requisitioned power, **schedule from DAM remains unchanged.** This may create a scenario where the total schedule exceeds the on-bar DC, leading to generation-demand imbalance and DSM implication on the generator due to under injection which is beyond reasonable control of the generator.

In view of the above difficulties, it is submitted to introduce a provision for adjustment of DAM schedule through SCUC/SCED-Down in case of USD, ensuring that total schedule does not exceed the on-bar DC. Therefore, Regulation 47 (2) (b) may be modified as below:

"(b). In case total requisitioned power cannot be supplied through other units in the same generating station on bar, the requisition from the beneficiaries shall be reduced in the ratio of requisitioned power.

Provided that if power scheduled through DAM cannot be supplied through other units in the same generating station on bar, such schedule shall be reduced through SCUC Down /SCED-Down ensuring that total schedule does not exceed the on-bar DC of the generating station."

6. **Issues related to shortening of bidding window in Phase-II:**

The draft Regulations envisages a two-phase implementation of shortening of RTM timelines, with Phase-I applicable up to 31.03.2027 and Phase-II coming into effect from 01.04.2027 onwards. Under Phase-I, although the overall timeline is proposed to be shortened, the existing 15-minute RTM bidding window is retained. However, in Phase-II, the available RTM bidding window is proposed to be reduced from the existing 15 minutes to 5 minutes.

Submission:

Implementation of this phase would consequently require appropriate system-level modifications, along with resolution of certain procedural and data-availability issues at both the bidding entity and NLDC ends. These measures would be essential to ensure that the latest, accurate and reliable data is made available within the significantly compressed bidding window and that bids can be prepared and submitted without compromising their accuracy or increasing the risk of bid rejection or regulatory/financial exposure.

It is acknowledged that the actual time required by an entity for uploading bids during the RTM bidding window may, in itself, be less than 15 minutes. However, the bid preparation process involves several activities that can only be undertaken after the conclusion of the final schedule revision permitted to Discom. In particular, the quantum of URS available for bidding has to be determined based on the latest final schedules and declared capability available through WBES. For generating entities such as NTPC, these inputs are made available through API-based integration with the NLDC database.

Based on the experience from automated bid preparation and submission, the following issues may therefore be addressed before shortening the existing RTM bidding window:

- **Delay in availability of updated WBES/API data:**

  Following expiry of schedule revision time (currently 75 min prior to delivery period) , there is a **time delay >3-min for data updating at WBES** and an **additional 1-2 minutes for API updating**, resulting in idle period of **5-6 min** (data can only be fetched after waiting for 6 minutes).

  This data latency needs to be addressed before reducing the RTM bidding window. If the bidding window is shortened without resolving the issue, there is a risk that bid quantities may

be calculated using an earlier schedule revision rather than the latest available revision. This may subsequently result in incorrect bid submission, rejection of bids, or exposure to DSM liability. Under the prevailing regulatory framework, the financial consequences of such an outcome would be borne by the generating entity.

- **Non-availability of NOC-limit information through API:**

  NOC limit for a time block is DC minus schedule of generating station after right to recall ends for beneficiaries. Generators are not provided with **NOC-Limit data in API** provided by WBES. This results in cases where bids are prepared at a revision number (6th minute) different from the revision number (13th minute) at which NOC-limit is checked at Exchange. This results in rejection of total bid quantum if bid quantum exceeds **NOC-Limit data**. Shortening of RTM bidding window without bid rejection can be achieved by providing NOC-limit to the generators in the API provided by WBES.

- **Communication and processing time**

  The whole process of RTM bidding requires communication across various nodes as shown in the figure below with approx. time taken in communication:



  The **time available for communication and processing** of data across different nodes after shortening is very less. This may lead to frequent bid missing incidents and implications as per LPSC rules.

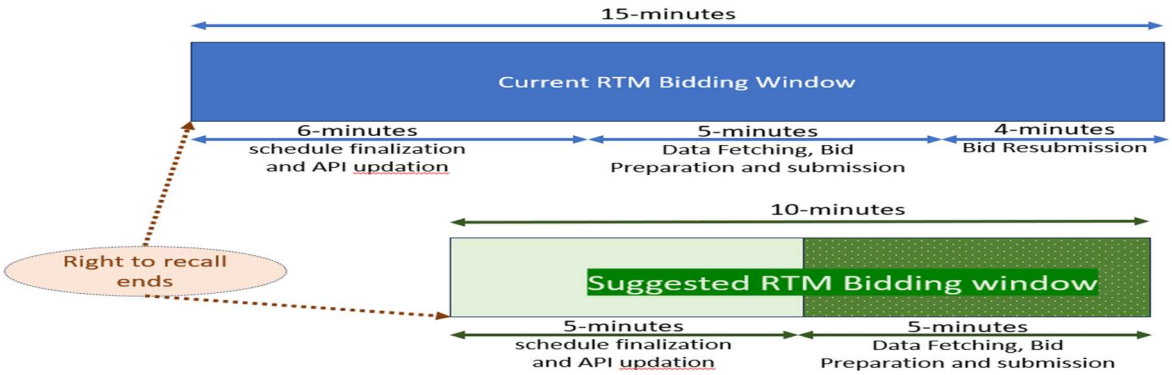
An illustration of 5-minutes trading window Inadequacy is attached as Annexure-I.

In view of the above, either of the following proposals may be considered:

Proposal-1:

As the shortening of RTM window to 5-minutes will lead to drastic increase in bid missing incidents, as major portion is consumed for schedule updating in API and data fetching, It is suggested to either:

- RTM bidding window time may please be continued to be kept at 15 Minutes. **OR**
- **Provide a buffer of 5 minutes** (i.e. right to recall ends 5-minutes before RTM bidding window starts), so that sufficient time is allowed for schedule finalization and API updating. RLDC to work on reducing network delays and data update time. Once this is achieved, RTM window to be shortened gradually.



Proposal-2:

Generators will bid from the start of Bidding Window for RTM, while cross checking NOAR NOC quantum on IEX end, bid quantum be accepted **minimum** of available NOAR NOC fetched on real time basis or bid quantum received instead of outright rejection.

This requires Regulatory sanction for IEX to modify the bid. This will eliminate bid rejections on IEX end and eliminate waiting time at generator end, while ensuring maximum up to NOAR NOC quantum cleared and eliminate more than DC over scheduling issues also. NOAR NOC quantum please be included in NLDC API being given to NTPC on real time basis to reduce RTM Bid rejections. **The proposed mechanism is illustrated as below:**

Generator Bid quantum (MW) for the Block 00:00-00:15 Hrs (**A**)	NOAR NOC Quantum (MW) for the Block 00:00-00:15 Hrs **(B)**	IEX cleared Quantum (MW) for the Block 00:00-00:15 Hrs to bid in the market	Remarks
100	99.5	0	Bid being rejected presently
100	99.5	99.5	Suggested for clearing MIN (A, B)

7. Energy Metering and Accounting in generating stations having Dedicated Transmission line (DTL):

Submission:

Regulation 49(12) of IEGC-2023 provides that the installation of Interface Energy Meters (IEMs) shall be in accordance with the CEA Metering Regulations 2006 and RLDC shall compute time block wise actual net injection and drawal of regional entities based on the IEM readings. As per the existing practice NTPC stations have been provided with Ex-bus ISTS connectivity and DC, APC and Energy charges for Section 62 generating stations are determined at the generator ex-bus as per CERC Tariff Regulations. Accordingly, PPAs also provide for ex-bus sale of power.

However, several upcoming NTPC stations have been granted connectivity to the ISTS through DTLs. Furthermore, some stations have been accorded dual connectivity to both the ISTS through DTL and the State Grid. It is pertinent to mention that, where connectivity to ISTS is through a DTL, the IEMs

are permitted to be installed only at the far end of the DTL as per CEA Metering Regulations. Consequently, energy accounting at such meter includes DTL losses, resulting in corresponding loss of energy-charge recovery by the generator. An illustration of DTL issue is attached as **Annexure-II**.

It is therefore submitted that a suitable relaxation may be provided to facilitate energy accounting and billing at the generator's ex-bus for section 62 generating stations connected to ISTS through a Dedicated Transmission Line.It is submitted that; a proviso may be inserted in Regulation 49(12)(f) as under:

"49(12)
(f) ……..
Provided that for a regional entity generating station whose tariff is determined under section 62 of the Electricity Act, connected to ISTS through a Dedicated Transmission Line, computation of time block wise actual net injection and drawal shall be based on meter installed at the generator's ex-bus.
……."

8. **Ramp rate of gas stations in combined cycle mode:** As per the Reg 45 (9)(a) (ii) of IEGC 2023, gas power plants shall declare a ramp up or ramp down rate of not less than 3% of ex-bus capacity corresponding to MCR on bar per minute. Though, gas-based generating stations are capable of declaring ramp rates of up to 3% per min in open cycle mode, their ramping capability in combined cycle is limited to 1% per minute in combined cycle mode due to inherent response time of the Waste Heat Recovery Boiler (WHRB), which has characteristics similar to coal-based generating units. It is proposed that the ramp rate requirement for gas stations in combined cycle mode be changed to 1% per minute and regulation 45(9)(a)(ii) of IEGC 2023 be modified suitably.

9. **Consent of beneficiaries for scheduling of infirm power**

The draft Regulation 25A(3) provides for advance notice of at least 7 days to the buyers for offering infirm power in the absence of any specific provisions of treatment of sale of power prior to achieving commercial operation under the contract. If buyer does not respond within 7 days the generating station shall be free to sell such power to any of the third party outside the Contract.

Submission:

Scheduling of infirm power is permitted only after successful completion of the trial run and a generator is already required to provide 48 hours prior notice for the trial run. Since successful completion of the trial run is subject to fulfilment of various tests and demonstration of the prescribed capabilities**,** it may not be feasible to ascertain seven days in advance whether the trial run would be successfully completed**.** Consequently, if a 7-day advance notice is mandated, the generating station may effectively have to wait for up to seven days after successful completion of

the trial run before scheduling/selling such infirm power. This may result in loss of opportunity for sale and avoidable non-utilisation of available generation.

Accordingly, the notice period may be reduced from **7 days to 1 day**. A 1-day notice period would provide reasonable opportunity to the contracted buyer to exercise its first right to procure the infirm power, considering that it would already have advance information regarding the proposed trial run through the 48-hour prior notice given by the generator. At the same time, it would provide the necessary flexibility to the generating station to offer such power to third parties in case the contracted buyer does not exercise its right within the stipulated period.

It is submitted that Regulation 25A(3)(a) may be modified as below:

*"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 **one (1) day**."*

10. PFR for Integrated ESS:

The Draft Regulation has made PFR mandatory for ESS under Regulation 30(10)(h).

Submission:

(i). Integrated BESS at thermal stations may be considered distinctly from standalone BESS for mandatory Primary Frequency Response (PFR) purpose as existing thermal units already provide PFR. Imposing independent PFR obligations on integrated BESS without considering the thermal units' existing response capability and common evacuation arrangement may lead to operational challenges as the capacity of integrated BESS has been finalized considering margin in the existing transmission evacuation system for its optimum utilization.

Moreover, BESS PFR capability depends on SoC, PCS rating, operating mode and available headroom. Mandatory capacity reservation may affect contracted peak-hour discharge commitments. Continuous PFR may increase battery degradation and decrease useful life due to cyclic operations.

The above considerations assume greater significance for BESS projects already awarded or under implementation, where the technical configuration, sizing, PCS capacity, battery warranty parameters may have been finalized without envisaging mandatory PFR capability. Introducing such an obligation subsequently may therefore necessitate changes in design philosophy, which were not factored into the tendering and project economics at the time of award.

In view of the above, Integrated BESS awarded before notification of these Regulations (2nd Amendment to IEGC 2023) may be exempted from PFR obligations.

(ii). Further, for Integrated BESS projects awarded after notification of these Regulations, a detailed procedure for PFR obligation may be prepared in consultation with all stakeholders. Such a procedure may take into account State of charge, Power Control System capacity and operating headroom. Recovery of additional degradation, RTE losses, auxiliary consumption and opportunity costs, with separate PFR measurement at thermal and BESS.

11. Mandatory SCED participation for all regional entity generating stations:

Submission:

At present participation in SCED is mandatory for Section 62 thermal generating stations, while it is voluntary for thermal generating stations whose tariff is not determined under Section 62. Around 58 stations are participating under SCED Mechanism **(Annexure-III).** Notably almost all of them are generating stations whose tariff is determined under section 62 of the Act.

It is submitted that bringing all eligible regional entity generating stations under the SCED framework would enlarge the pool available for system-wide economic optimization and enable generation to be dispatched on the basis of relative variable cost, while respecting applicable system security constraints. A broader pool of flexible generation would also provide greater operational flexibility to the system operator, particularly in managing increasing variability associated with renewable energy integration.

In view of the above, it is submitted that participation in Security Constrained Economic Despatch (SCED) may be made mandatory for all regional entity generating stations, irrespective of their tariff determination mechanism, subject to technical feasibility and scheduling capability.

12. DSM aggregation principle for Multistage thermal stations:

Submission:

IEGC already recognizes aggregation principles for renewable energy generators through the Qualified Coordinating Agency (QCA) framework, whereby multiple generating units connected to a pooling station are treated as a single entity for scheduling, forecasting, operational coordination and deviation settlement.

Similar principles may be considered for large thermal generating complexes comprising multiple stages located at the same site and operated as an integrated station. Multi-stage generating stations such as Vindhyachal, Rihand, Korba, Sipat and Ramagundam function operationally as a single generating complex with common fuel management, common dispatch centre, shared infrastructure and unified operational decision making. However, DSM accounting are presently carried out stage-wise, which may result in DSM exposure to the stations and restrict operational flexibility.

It is submitted that, commercial aspects such as beneficiary allocation, tariff determination, capacity charges, generation incentive and part-load compensation may continue to remain stage-

specific, while DSM may be considered at the aggregated station level for multistage thermal station to enable operational flexibility and reduce DSM implications.

13. Signing authority of certificate of compliance before declaration of COD:

Regulation 26 (1b), (2b), (4a) of principal Regulations provide that the certificates **of compliance** required to be submitted before the CoD shall be signed by the authorized signatory not below the rank of CMD or CEO or MD of the generating company/Pumped Storage Plant, as the case may.

Submission:

It is submitted that to provide necessary **administrative and operational flexibility**, particularly in large generating companies where different functional areas are entrusted to respective Board-level Directors, the above requirement may be suitably amended to also permit a **Director on the Board of the company, duly authorized by the Board,** to sign the certificate of technical compliance prior to CoD.

Since such certification would be made by a Director only pursuant to due authorization of the Board, the **requisite level of responsibility, accountability would continue to be maintained**, without necessarily requiring the certificate to be signed only by the CMD/CEO/MD.

Accordingly, it is requested that "Director on the Board, duly authorized by the Board of the company" may also be included as an eligible signatory under Regulations 26(1)(b), 26(2)(b) and 26(4)(a) as under:

*"26(1)(b). The certificates required under sub-clause (a) of this clause shall be signed by the authorized signatory not below the rank of CMD or CEO or MD or **Director on the Board duly authorized by the Board** of the generating company and shall be submitted to the concerned RLDC and to the Member Secretary of the concerned RPC before the declaration of COD.*

*26(2)(b). The certificates required under sub-clause (a) of this clause shall be signed by the authorized signatory not below the rank of CMD or CEO or MD or **Director on the Board duly authorized by the Board** of the generating company and shall be submitted to the concerned RLDC and to the Member Secretary of the concerned RPC before the declaration of COD.*

*26(4)(a).The generating station based on wind and solar resources, the ESS and the hybrid generating station shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD or **Director on the Board duly authorized by the Board** to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD, that the said generating station or the ESS as the case may be, including main plant equipment such as wind turbines or solar inverters or auxiliary systems, as the case may be, has complied with all relevant provisions of CEA Technical*

Standards for Connectivity, CEA Technical Standards for Communication, Central Electricity Authority (Measures relating to Safety and Electricity Supply) Regulations,2010 and these regulations."

14. Provision of Regulation of access to defaulting entities:

Regulation 45(16) provides as under:
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:

(i) T-GNA, including already approved T-GNA, for the sale and purchase of electricity through short term contracts, including in the power exchange, shall be regulated entirely:
Provided further that the NLDC may, under exceptional circumstances for grid security, temporarily review the regulation of T-GNA and record the reasons for doing so in writing.

(ii) If, even two months after the regulation of the T-GNA, the dues remain unpaid, apart from the regulation of the short term contracts under T-GNA in its entirety, the short term contracts under GNA shall be regulated entirely.

(iii) The reduction or withdrawal of access for sale and purchase of electricity through contracts other than short-term contracts shall be in such a manner that the quantum of reduction in drawal or injection schedule increases progressively by five per cent (5%) for each month of default.

(b) Upon payment of outstanding dues or maintaining adequate Payment Security Mechanism, as the case may be, the regulation of access shall cease to operate, and access shall be restored at the earliest, but not later than one day, excluding the day on which payment is made.

Submission:

(i.) Trigger date for regulation under sub-clause (a)(iii):
It may be clarified as to when the progressive reduction of drawal/injection schedule by 5% for each month of default for contracts other than short-term contracts under sub-clause (a)(iii) shall commence.

(ii.) Sequencing of regulation where an earlier provision a(i) is not applicable:
It may further be clarified whether the regulation of power under sub-clauses (a)(ii) and (a)(iii) shall commence only after exhaustion of the timeline prescribed under the preceding clause,

irrespective of whether the preceding provision is applicable to the defaulting entity or not or if the preceding provision is not applicable, the regulation shall directly commence under the next applicable provision.

For instance, where a defaulting entity has no short-term contracts under T-GNA, it may be clarified whether regulation of power under (a)(ii) shall commence after 2 months of the default trigger date or from the default trigger date.

(iii.) The draft Regulations have incorporated a provision for regulation of access to entities in the event of default in payment of statutory charges or non-maintenance of the prescribed payment security mechanism, after the default trigger date.

However, similar regulatory protection is also required where a buyer defaults in payment of outstanding dues payable to a seller, as such dues also arise from contractual or regulatory obligations. Therefore, to ensure parity in treatment of payment defaults and adequate protection of sellers, the following provision may be added in Regulation 45(16):

"Provided that electricity shall be scheduled or dispatched only if timely payment is made and adequate Payment Security Mechanism is maintained as per the contracts or the Rules prescribed by the Central Government or by the Commission.

Provided further that non-maintenance of Payment Security Mechanism or default in payment of outstanding dues, such defaulting entities shall be subject to Regulation of Power Supply & Transmission Access as per the contracts or the Rules prescribed by the Central Government or by the Commission."

15. Congestion charge to wheeling region in case of simultaneous congestion:

The Draft 30A(1)(b) as under:

"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 irrespective of whether the deviation apparently relieves or aggravates the congestion on a particular corridor."

Submission:

Congestion charge is payable by regional entities causing congestion and receivable by entities relieving it. Regulation 30A(1)(b), however, deals with simultaneous congestion involving a wheeling region and provides that any deviation by a regional entity in that region attracts congestion charge, irrespective of its direction or size.

A special methodology for a wheeling region may be justified, since the impact of a deviation on simultaneously congested corridors cannot always be unambiguously identified. However, levying congestion charge on every deviation, without any tolerance, would in effect impose a zero-deviation requirement on all regional entities in that region. Such a requirement is not practicable. Small deviations from schedule are inherent in real-time system operation, arising from normal variations in generation and load and from mandatory grid-support actions such as primary frequency response.

A reasonable tolerance band may be provided so that congestion charge is attracted only by material deviations. Notably, NLDC, in its revised draft procedure dated 26.12.2025 for the treatment of the wheeling region during simultaneous congestion, has itself proposed such a threshold: the charge applies to deviations by entities in the wheeling region only where the deviation exceeds ±20 MW in the time block in which congestion charge is invoked. Though para 14.5 of the Explanatory Memorandum quotes this proviso, the proviso does not appear in the draft Regulation 30A(1)(b).

In view of the above, it is proposed that the congestion charge under Regulation 30A(1)(b) apply to deviation by entities in the wheeling region only where the deviation is more than ±20 MW tolerance (or such other threshold as the Commission considers appropriate) in the time block when congestion charge is invoked.

16. Accounting and settlement of congestion charges:

Draft Regulation 30(A)(6) and 30(A)(7) provide as under

(6) Payment of Congestion Charge. *The Regional Entity liable to pay congestion charge, shall deposit the amount in Pool Account within 10 days of issue of statement by the Regional Power Committee Secretariat: Provided that when payment of congestion charge is delayed beyond the due date, the Regional entity responsible for delay in depositing congestion charge amount shall be liable to pay interest at the rate of 0.04% per day.*

(7) Release of Congestion Charge Amount. *The RLDCs shall, within two working days of receipt of congestion charge, release the amount payable to the Regional Entity entitled to receive congestion charge, along with interest, if any, on account of delay in payment of congestion charge.*

Submission:

The draft specifies due date and delayed payment surcharge for payment of congestion charges by defaulting entities. However, no corresponding timeline and interest rate for delayed payment mechanism has been provided for disbursement of congestion charge to recipient entities. It is

submitted that the concept of carrying cost is well-recognized by statutory authorities and judicial forums. It is intended to safeguard the interests of the receiving party by compensating for the time value of money.

For the sake of clarity and to ensure equitable treatment of both incoming and outgoing payments, it is suggested that Draft Regulation 30(A)(7) may please be modified as under:

"(7). Release of Congestion Charge Amount. *The RLDC shall, within 12 days of issue of statement by the Regional Power Committee Secretariat, release the amount payable to the Regional Entity entitled to receive congestion charge.*

Provided that when payment of congestion charge is delayed beyond 12 days of the issue of statement by the Regional Power Committee Secretariat, the Regional entity shall be paid interest at the rate of 0.04% per day."

Further, it is humbly submitted that a provision of carrying cost may also be provided in case of delay in issuance of account by RPCs.

17. Exemption from applicability of Congestion charges in case of schedule below Minimum Turn Down Level:

Submission:

The rapid increase in renewable energy capacity additions, combined with periods of low demand has created significant operational challenges for the grid as well as thermal generators. The generation from Variable RE is high during solar hours, consequently, the requisitions/dispatch from several inter-state thermal generating stations by Discoms / beneficiaries is nil or negligible during solar hours often resulting in injection schedules below the Minimum Turn Down Level (MTL).

Notably some of such units are accommodated by NLDC at MTL through SCUC provisions and many others (which are scheduled above MTL in at least in 8-time blocks in peak hours) are considered for MTL support through SCED, subject to availability of down reserves in the SCED stack stations. For the stations which are not extended SCUC support, there is a provision of taking the unit under shutdown. However, it is observed that shut down of units in case of below MTL schedule in intermittent blocks is operationally not practical and cost effective. Therefore, it is prudent that such units remain on bar for meeting non-solar and peak hour schedule provided by the beneficiaries. The same is in line with 9/SM/2024 order of the Hon'ble Commission which provides that *"Such generating station should endeavor to plan as far as possible the USD in such a manner that the maximum number of units are kept on bar, keeping in view the economy and efficiency of the units of the generating station."*

Under the above circumstances, uncontrollable injection arising from generating schedules below MTL does not stem from any commercial decision or controllable action of the generator but is an operational compulsion necessary to keep the units on bar, avoid frequent shutdowns/start-ups and

to ensure safe and reliable operations. Such injections are beyond the reasonable control of the generator and occurs to maintain technical minimum loading of the units / machines.

Under the above circumstances and as per the extant Deviation Settlement Mechanism (DSM), these thermal stations are subjected to heavy penalties for over-injection, which are further aggravated by congestion-related charges. Given the unique operational constraints arising from high RE penetration, this special circumstance merits due consideration, and undue double penalization of such thermal stations may be avoided.

In view of the above, it is humbly requested that Congestion charges may not be levied on thermal stations for deviation attributable solely to schedules falling below MTL.

18. **Incorporation of the provision of SM order regarding revision of schedule of RE Generators under T-GNA**

Submission: Considering the difficulties in schedule revision Hon'ble Commission vide Suo motu Order 14/SM/2023 dtd 30.09.23, has clarified that a generating station acting as a Wind/Solar (WS) seller or Run-of-River (RoR) generating station shall be permitted to revise its schedule under Regulations 49(8) and 49(9) of the IEGC, as applicable from the 7th/8th time block, irrespective of whether the generating station is operating under GNA or deemed T-GNA, in the case of bilateral transactions. Accordingly, the commission has allowed revision of schedule in cases 2,3,4 also in addition to the existing revision provision for revision of schedule case 1 as described below:

Cases	Generating station under	Buyer schedules power of generating station under:
1	GNA	GNA
2	Deemed T-GNA	GNA
3	GNA	T-GNA
4	Deemed T-GNA	T- GNA

However, the relaxation provided by the Hon'ble commission has not been incorporated like other provisions of the SM order.

In view of the above, it is requested that the same may be expressly incorporated in the Regulation 49(8) and 49(9) as under:

"(8) In case of requirement of revision of schedule due to forecasting error, a WS seller may revise its schedule only in case of bilateral transactions (irrespective of whether such a generating station is under GNA or deemed T-GNA or buyer schedules under GNA or T-GNA) and not in case of collective transaction. Such revision of schedule shall become effective from the time block and in the manner as specified in sub-clause (c) of clause (4) of this Regulation.

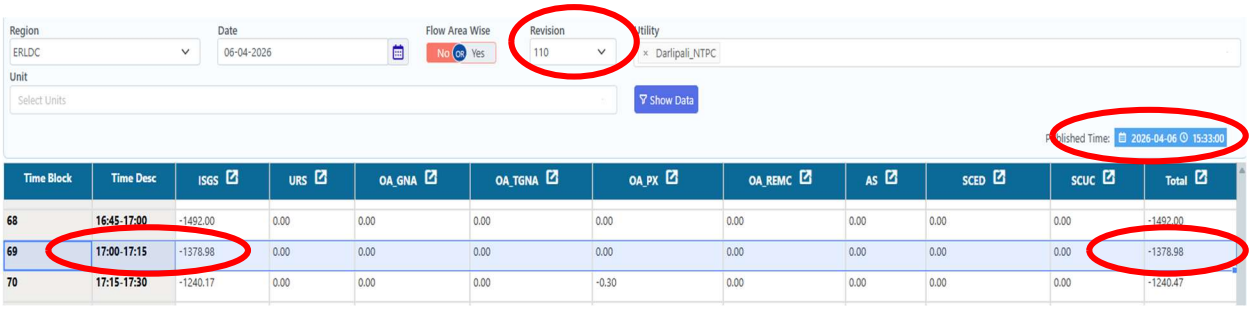
(9) In case of requirement of revision of Declared Capacity due to forecasting error, a RoR generating station may request for revision of its Declared Capacity and schedule only in case of bilateral transactions (irrespective of whether such a generating station is under GNA or deemed T-GNA or buyer schedules under GNA or T-GNA) and not in case of collective transaction. Such revision shall become effective from the time block and in the manner as specified in sub- clause (c) of clause (4) of this Regulation."

Annexure-I

5-minutes trading window Inadequacy example

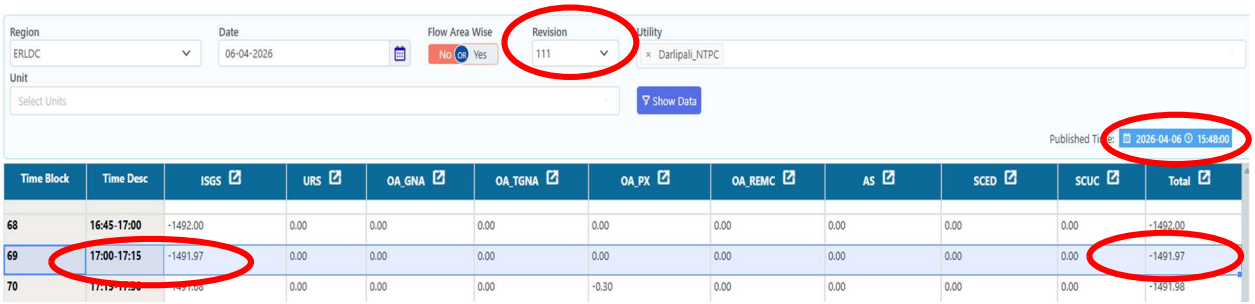
(Darlipalli station on 6th April (17:00 hrs to 17:30 hrs Delivery blocks)

For delivery blocks 69-70 Bidding starts from 15:45



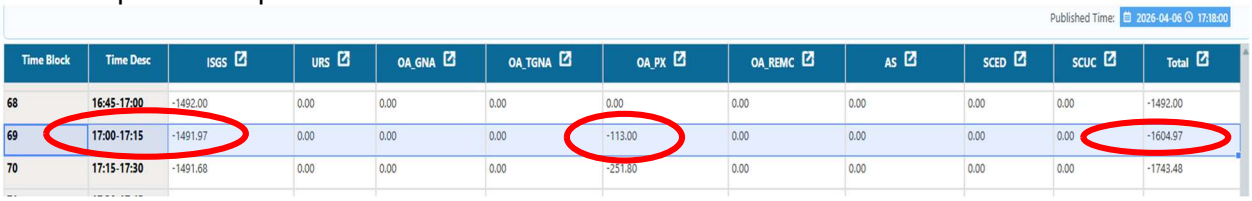
Time Block	Time Desc	ISGS	URS	OA_GNA	OA_TGNA	OA_PX	OA_REMC	AS	SCED	SCUC	Total
68	16:45-17:00	-1492.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1492.00
69	17:00-17:15	-1378.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1378.98
70	17:15-17:30	-1240.17	0.00	0.00	0.00	-0.30	0.00	0.00	0.00	0.00	-1240.47

Revision in SG was published 3 minutes after 15:45 and updated in API after 15:52 (>7 minutes).



Time Block	Time Desc	ISGS	URS	OA_GNA	OA_TGNA	OA_PX	OA_REMC	AS	SCED	SCUC	Total
68	16:45-17:00	-1492.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1492.00
69	17:00-17:15	-1491.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1491.97
70	17:15-17:30	-1491.68	0.00	0.00	0.00	-0.30	0.00	0.00	0.00	0.00	-1491.98

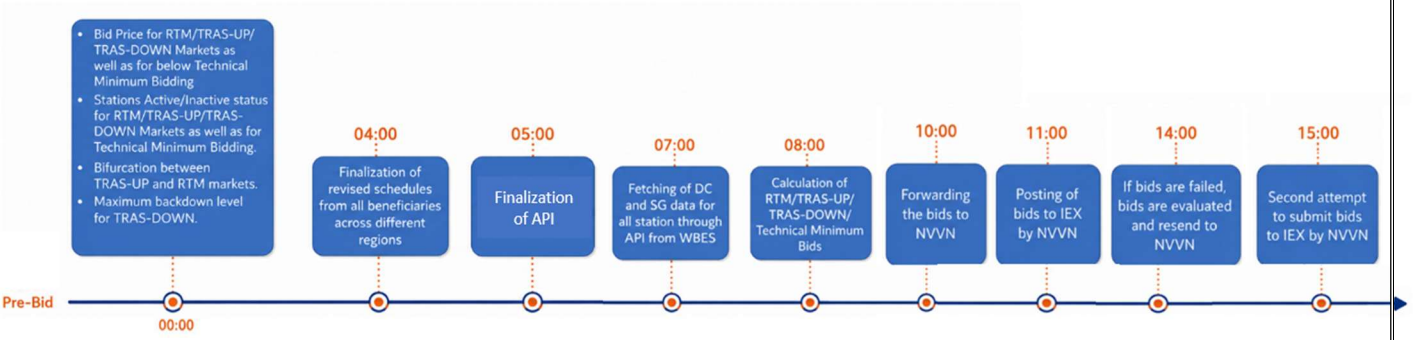
Bid was placed as per Revision-110.



Time Block	Time Desc	ISGS	URS	OA_GNA	OA_TGNA	OA_PX	OA_REMC	AS	SCED	SCUC	Total
68	16:45-17:00	-1492.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-1492.00
69	17:00-17:15	-1491.97	0.00	0.00	0.00	-113.00	0.00	0.00	0.00	0.00	-1604.97
70	17:15-17:30	-1491.68	0.00	0.00	0.00	-251.80	0.00	0.00	0.00	0.00	-1743.48

Final revision not published till 15:52 in API data & bidding done on previous revision resulted in SG> DC.

RTM bid process starts after 6-min, after finalization of schedule and update in API, as suggested by NLDC in meeting for LPSC rules Compliance.



Any bid rejection due to mismatch with NOC limit, cannot be reattempted in 5-minutes.

Annexure-II

Illustration of the issue in Energy accounting and scheduling in case of a section 62 station connected to ISTS through DTL.

- **Regulation 49(12) of IEGC-2023** provides that the installation of Interface Energy Meters (IEMs) shall be in accordance with the CEA Metering Regulations 2006 and RLDC shall, compute time block wise actual net injection and drawal of regional entities based on the IEM readings.

  CEA Metering Regulations-2006 provides for installation of 'Interface Meter' for accounting and billing of electricity at the point of interconnection between electrical systems of generating company and ISTS or Intra-State Transmission System.

  In view of the CEA Regulations, interface meters are to be installed only at the point where DTL is connected to ISTS i.e. far end of the DTL from the generating stations.

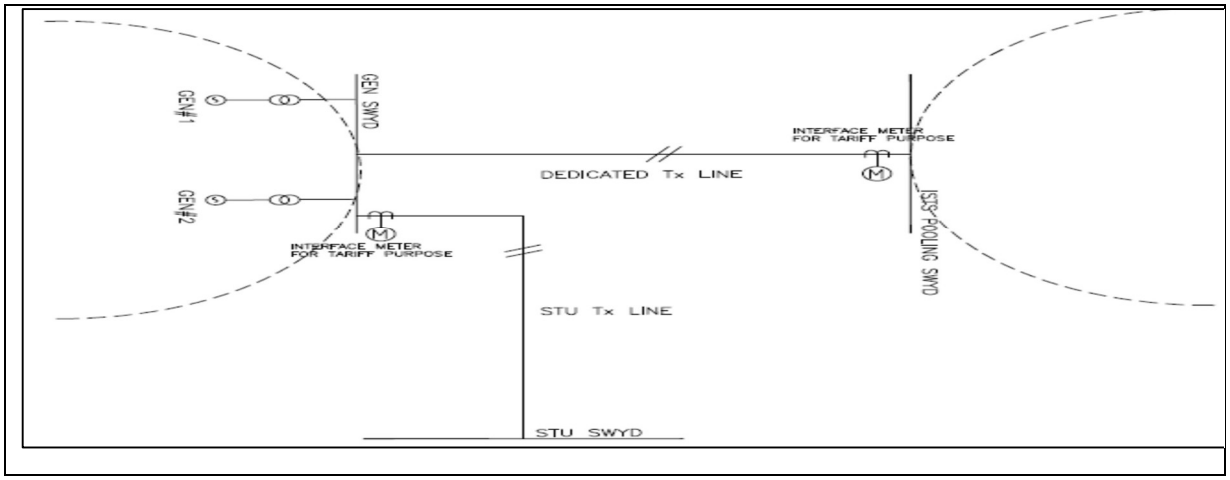
- Many upcoming NTPC stations such as Talcher TPS-III, Lara-II & Singrauli-III have been granted ISTS connectivity through DTL. The length of DTLs is more than 100kMs for TTPS-III & Lara-II. Transmission losses in DTL significantly vary from cases to case depending on the length, design and flow of power.

  For section 62 stations, APC, declared capacity and Tariff are determined at the ex-bus of a station under extant Tariff Regulations. Accordingly, NTPC PPAs provide for ex-bus sale of the electricity.

  Consequently, Energy accounting at such meter will include DTL losses, resulting in corresponding loss in energy-charge recovery by the generator.

  Further, the issue of transmission losses becomes more complicated in the cases where DTL built in parallel to STU transmission line in case of Dual connectivity. Ex. Talcher TPS-III.

Fig-1 Typical diagram of a generating station with dual connectivity (to ISTS through DTL)



It is evident from the fig-1 that the generation switchyard is **virtually acting as a ISTS drawal point for the STU Network**. Power flow in the proposed DTL is not exclusively dependent on the generating station. Power flow shall be as per network conditions. Even under Low schedule, Reserve Shut down and Planned/forced outages, Interchange of power possible between ISTS and STU network.

Moreover, in case of Dual connectivity, there are **two interface points** one with STU and other with CTU. DC and scheduling of a generator is feasible at a single point only and **DC declaration** and **Scheduling** at far end of DTL is not feasible.

In view of the above technical /commercial constraints, and to ensure the recovery of the Energy charges by a section 62 generator, it would be prudent to permit such stations to declare DC at the generator's ex-bus. Accordingly, metering and accounting of the energy may be allowed at the ex-bus of the station and DTL loss may be added to ISTS losses.

It is therefore submitted that a suitable provision be added to Regulation 49(12) of IEGC, 2023 to facilitate energy accounting and billing at the generator's ex-bus for Section 62 generating stations connected to ISTS through DTL.

List of SCED Generators as per Monthly Statement for Aug'26:			
S.No.	**SCED Generators**	**Company**	**Region**
1	BARH	NTPC	ER
2	BRBCL	BRBCL	ER
3	Darlipali STPS	NTPC	ER
4	Farakka STPP-I&II	NTPC	ER
5	Farakka STPP-III	NTPC	ER
6	Kahalgaon STPP-I	NTPC	ER
7	Kahalgaon STPP-II	NTPC	ER
8	Maithon Power Ltd (MPL)	MPL	ER
9	Muzaffarpur TPS-II	NTPC	ER
10	NPGC	NTPC	ER
11	Talcher STPS-I	NTPC	ER
12	Barh-I	NTPC	ER
13	North Karanpura STPP	NTPC	ER
14	PTPS_I	PVUNL (NTPC JV)	ER
15	Ramagundam STPS-I&II	NTPC	SR
16	Ramagundam STPS-III	NTPC	SR
17	Simhadri STPS-II	NTPC	SR
18	Talcher STPS-II	NTPC	SR
19	Vallur TPS	NTECL (NTPC JV)	SR
20	NLC Tamil Nadu Power Ltd (NTPL)	NLC	SR
21	Simhadri STPS-I	NTPC	SR
22	Kudgi STPS Unit I	NTPC	SR
23	Telangana STPP	NTPC	SR
24	Sipat STPS-I	NTPC	WR
25	Sipat STPS-II	NTPC	WR
26	Korba STPS-III	NTPC	WR
27	Korba STPS-I&II	NTPC	WR
28	Sasan	Sasan Power Ltd.	WR
29	Vindhyachal STPS-II	NTPC	WR
30	Vindhyachal STPS-III	NTPC	WR
31	Vindhyachal STPS-IV	NTPC	WR
32	Vindhyachal STPS-V	NTPC	WR
33	Vindhyachal STPS-I	NTPC	WR
34	NTPC-SAIL Power Company Limited (NSPCL)	NSPCL (NTPC JV)	WR
35	Mouda STPS-II	NTPC	WR

36	Mouda STPS-I	NTPC	WR
37	Gadarwara STPS	NTPC	WR
38	Solapur STPS	NTPC	WR
39	Lara STPS	NTPC	WR
40	Khargone STPS	NTPC	WR
41	ANTA CRF	NTPC	NR
42	DADRI CRF	NTPC	NR
43	AURAIYA CRF	NTPC	NR
44	Dadri TPS-I	NTPC	NR
45	Dadri TPS-II	NTPC	NR
46	Indira Gandhi STPS (IGSTPS-JHAJJAR)	APCPL (NTPC JV)	NR
47	Rihand STPS-I	NTPC	NR
48	Rihand STPS-II	NTPC	NR
49	Rihand STPS-III	NTPC	NR
50	Singrauli STPS	NTPC	NR
51	Tanda STPS-II	NTPC	NR
52	Unchahar TPS-I	NTPC	NR
53	Unchahar TPS-II	NTPC	NR
54	Unchahar TPS-III	NTPC	NR
55	Unchahar TPS-IV	NTPC	NR
56	Bongaigaon TPS	NTPC	NER
57	AGTCCPP_APM	NEEPCO	NER
58	AGBPP_APM	NEEPCO	NER