ENERGY ANALYTICS LAB
Department of Industrial and Management Engineering
Indian Institute of Technology Kanpur

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Power Chronicle

Editorial

Increasing share of variable renewable energy (VRE) raises an additional challenge for the system operator to address imbalances on account of uncertainty of VRE generation and electricity demand. The proposed framework by CERC for introducing the secondary reserves ancillary services (SRAS) and tertiary reserve ancillary services (TRAS) aims to address operational challenges faced by the system operator at different time scales. EAL has identified various issues that needs attention - definitional aspects, timeline for activation, price discovery mechanism, and reasonableness of incentives and alternate methodology for allocation among SRAS-Up providers. Adoption of pay-as-bid market clearing mechanism for TRAS would ensure that there is no super normal profit earned on a capacity, whose fixed charges have been paid up. This would also avoid market manipulations that may be caused by the high-cost marginal generator.

Implementation of Market Based Economic Dispatch (MBED) can enhance overall economy of power procurement across the country. Initial experience would help identify room for improvement and also assist evaluation of its impact on various stakeholders. Loss of flexibility to recall by the distribution utilities should be evaluated in view of overall benefit of MBED. The transition phase should ensure support for capacity building of discoms to sensitise the need for cost optimisation, improve forecasting capabilities and enable efficient decision making. Some of the operational aspects of MBED need fine tuning. The proposed upper limit for margin on sale of URS power is significantly higher, as the generators do not face any additional risk on account of sale of such power. Simultaneously, flexibility needs to be provided to generators for cost optimisation across all generating assets subject to transmission limitation and ensuring that there is no abuse of market power.

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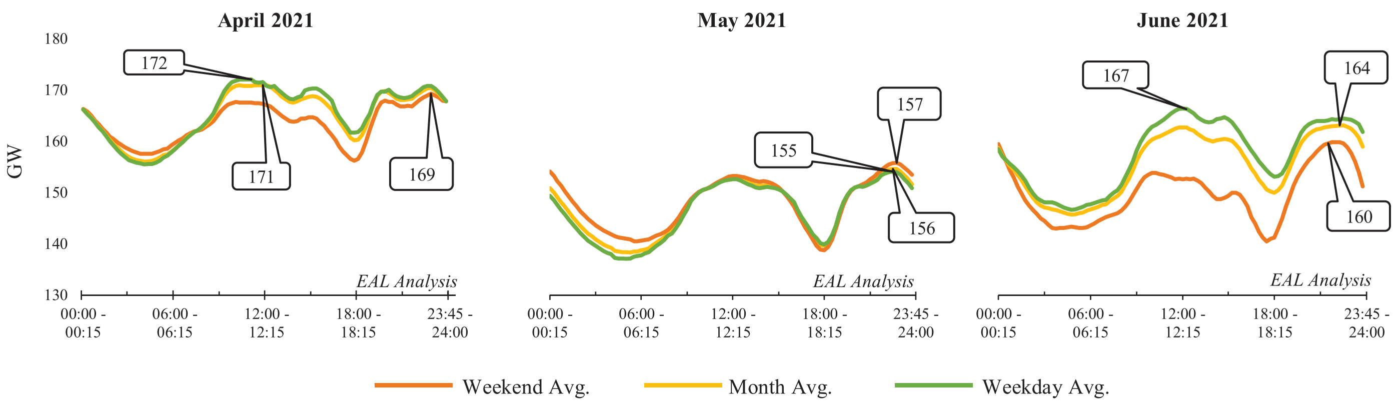
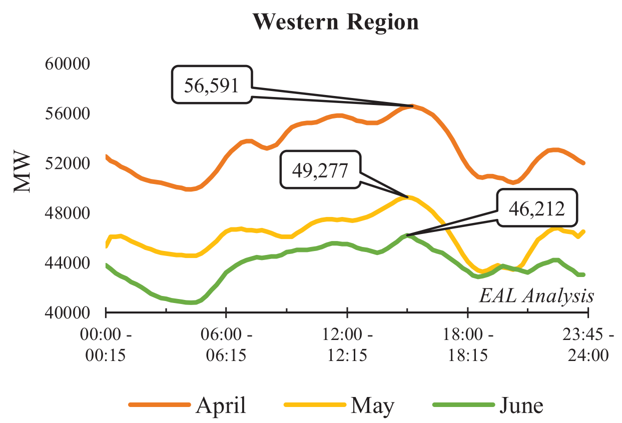
Power System Overview & Analysis

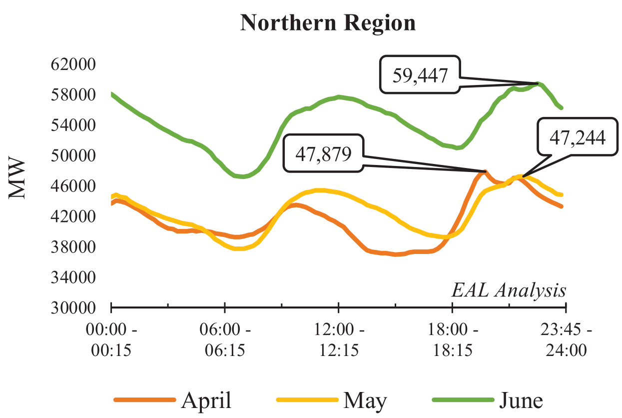
All India Demand Met Profile

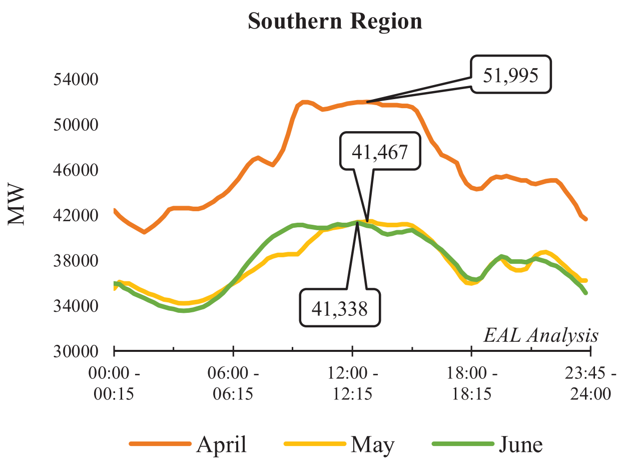


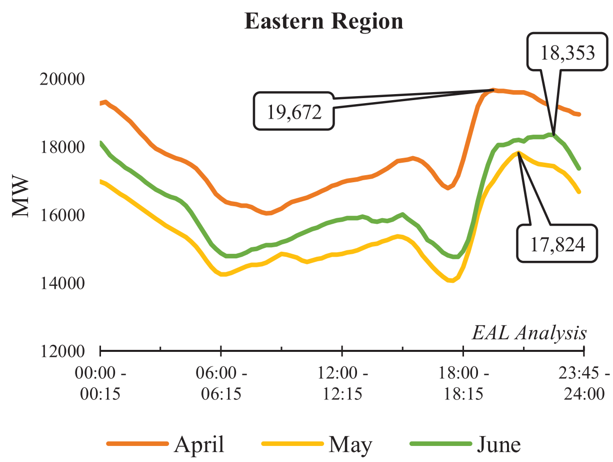
From April to June quarter, all India peak demand reached 191.24 GW (12:45 - 13:00) on 30th June 2021, about 15.97 percent higher than the previous year's peak demand recorded at 164.9 GW (22:15 - 22:30) on 23rd June 2020, during the same quarter.

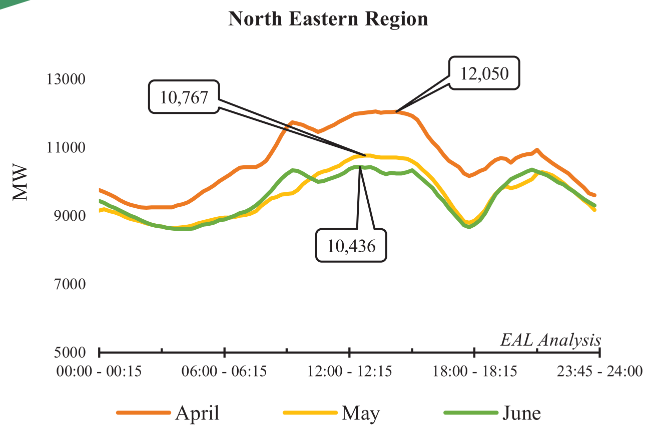
Region-wise Demand Met Profile







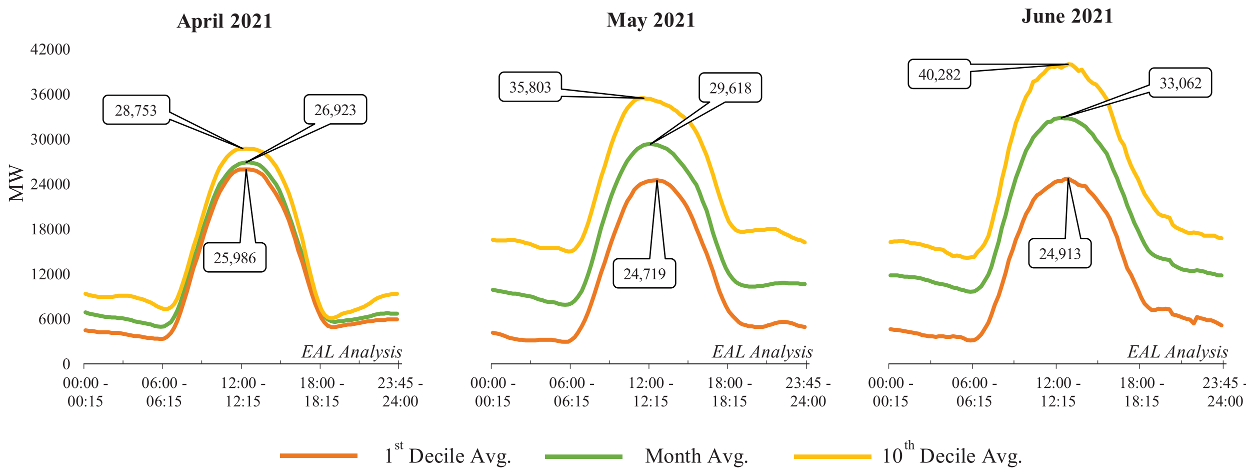




- Significant variation in demand profile can be seen in the month of April, May and June across some regions. Northern region witnessed a lower demand while the other four regions are on the higher side of the demand in the month of April.
- Eastern and Northern region have a significant rise in the demand during the evening time between 18:00 – 20:00 hours.

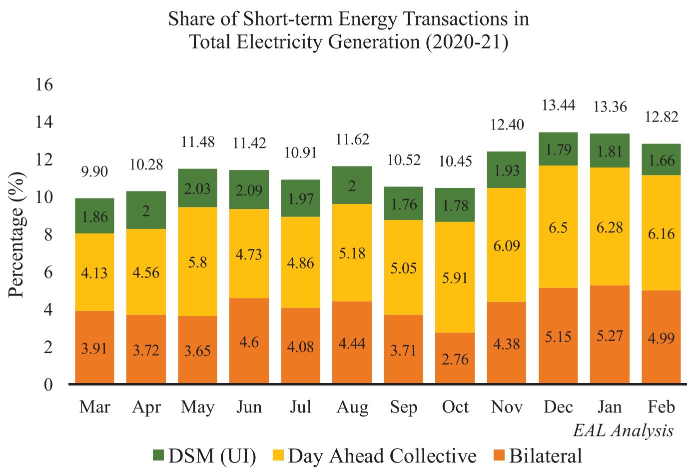
Demand and generation profiles at national, regional, and state-level can be accessed on EAL's web portal.

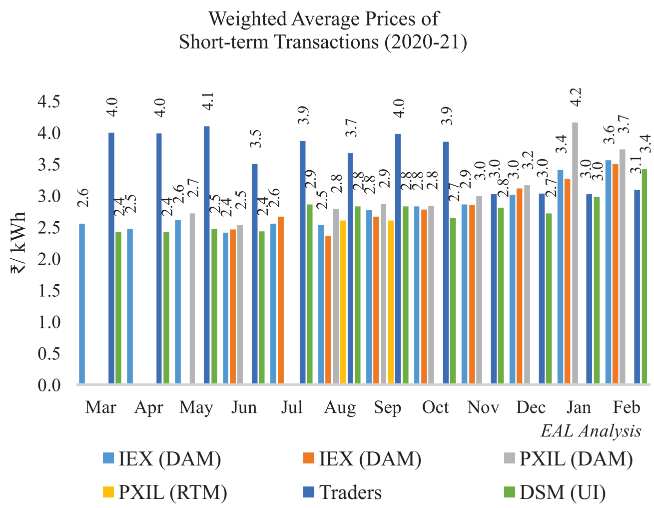
All India Renewable Energy (RE) Generation Profile



All India peak RE generation reached 41.30 GW (11:45 - 12:00) on 11th June, 2021, about 18.95% higher than the previous year's peak of 34.72 GW (13:45– 14:00) on 19th June, 2020 during the same quarter.

Short-term Energy Transactions





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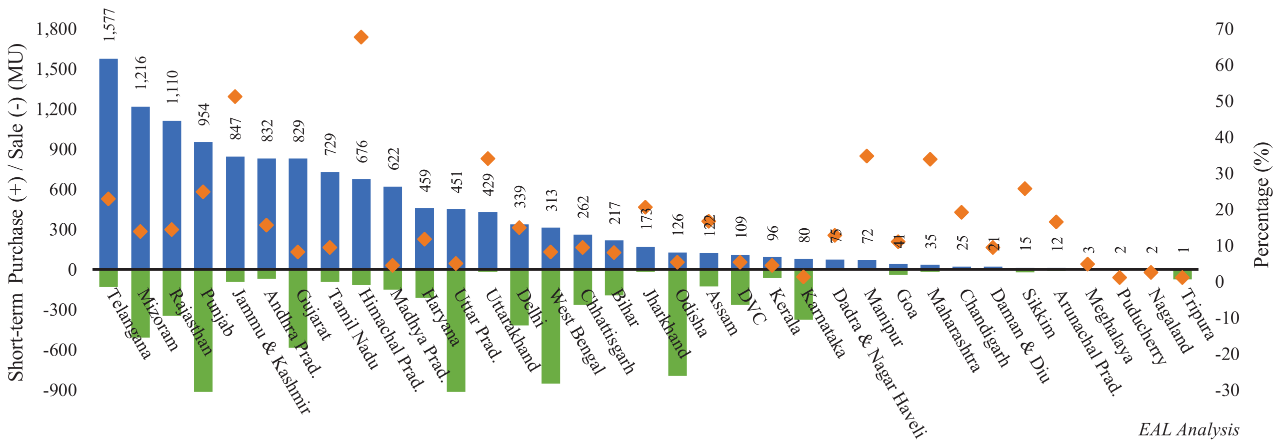
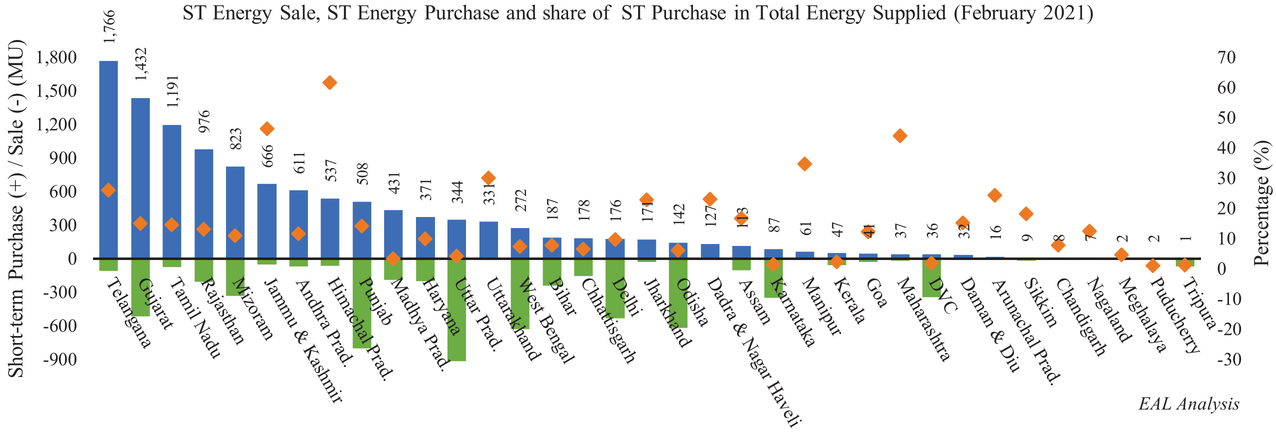
Monthly Short-term (ST) Purchase and Sale Quantum across States

ST Energy Sale, ST Energy Purchase and share of ST Purchase in Total Energy Supplied (January 2021)



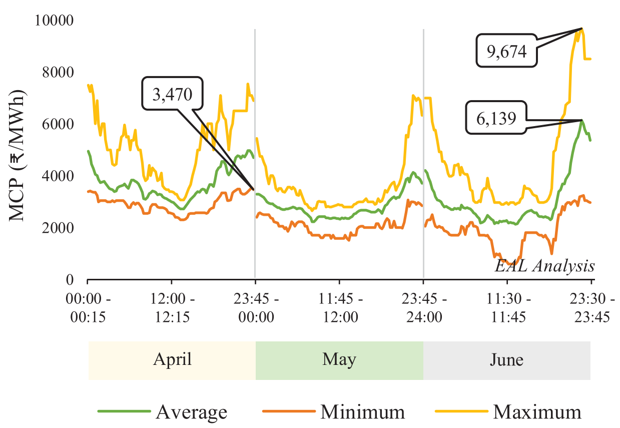
ST Energy Sale, ST Energy Purchase and share of ST Purchase in Total Energy Supplied (February 2021)



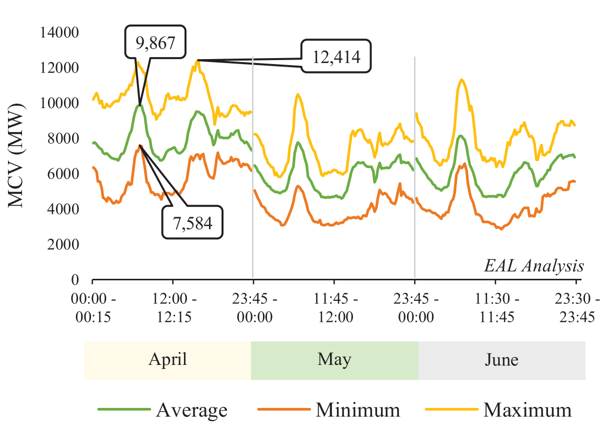
Power Market Overview & Analysis

DAM – Market Clearing Price (MCP) & Market Clearing Volume (MCV)

DAM Monthly Average, Maximum, & Minimum MCP

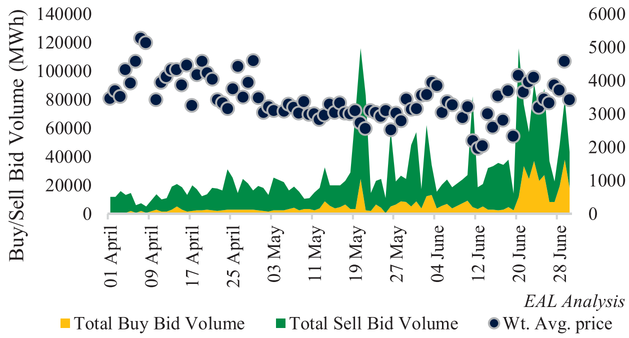


DAM Monthly Average, Maximum, & Minimum MCV

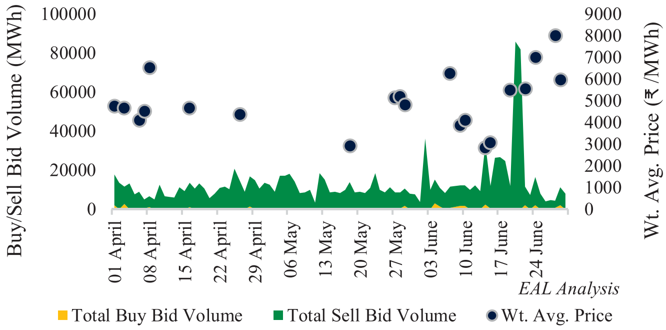


Term-Ahead Market (TAM)

Daily Day-Ahead Contigency Transactions



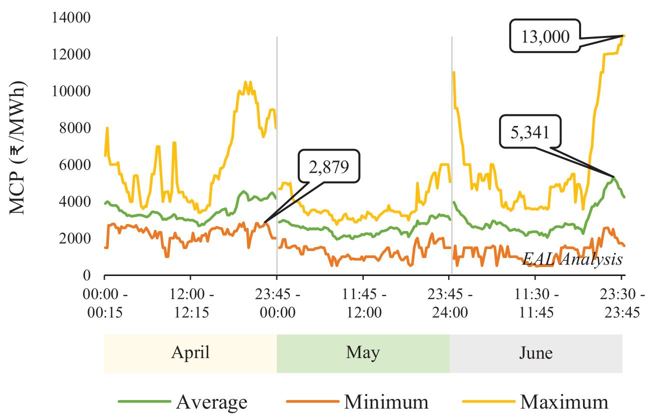
Daily Intra-Day Transactions



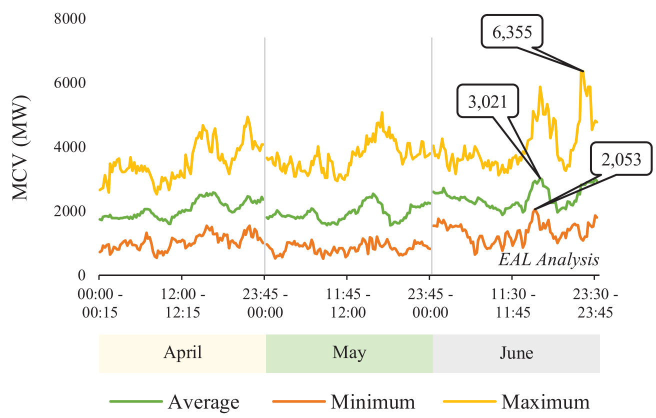
The weighted average clearing price observed in Intra-day market during April to June quarter is higher in comparison to the Day-Ahead Contingency market. Also, the proportion of sell bids is much higher when compared to purchase bids placed in the Term-Ahead Market.

RTM – Market Clearing Price (MCP) & Market Clearing Volume (MCV)

RTM Monthly Average, Maximum, & Minimum MCP

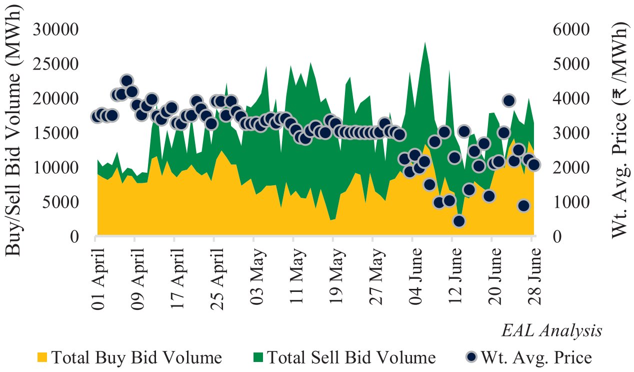


RTM Monthly Average, Maximum, & Minimum MCV

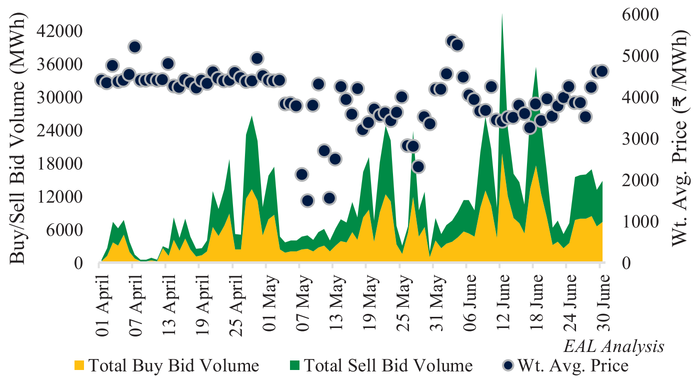


Green Term-Ahead Market (G-TAM)

Daily Day-Ahead Contingency Transaction - Solar



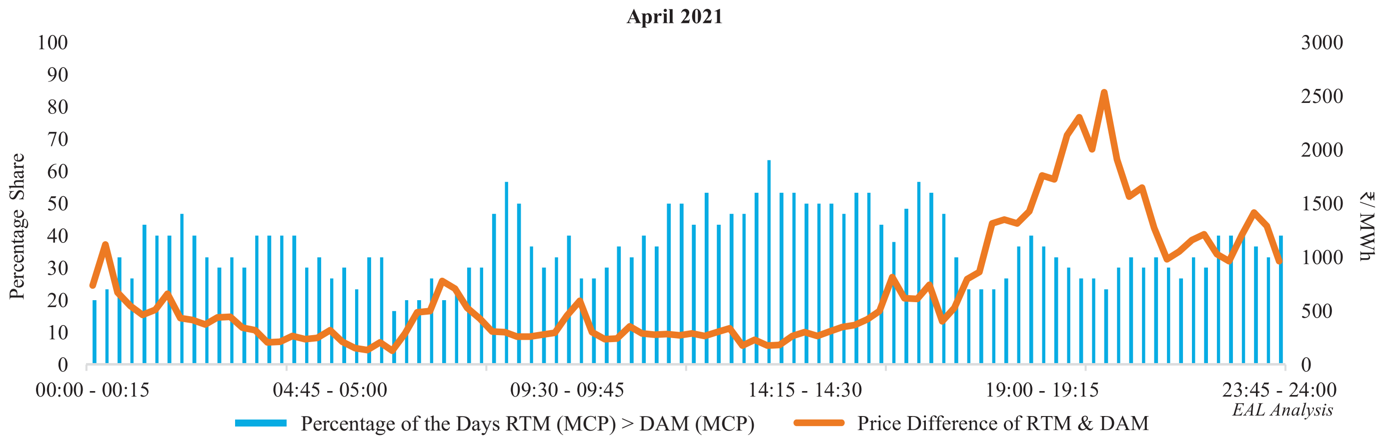
Daily Day-Ahead Contingency Transaction - Non-Solar

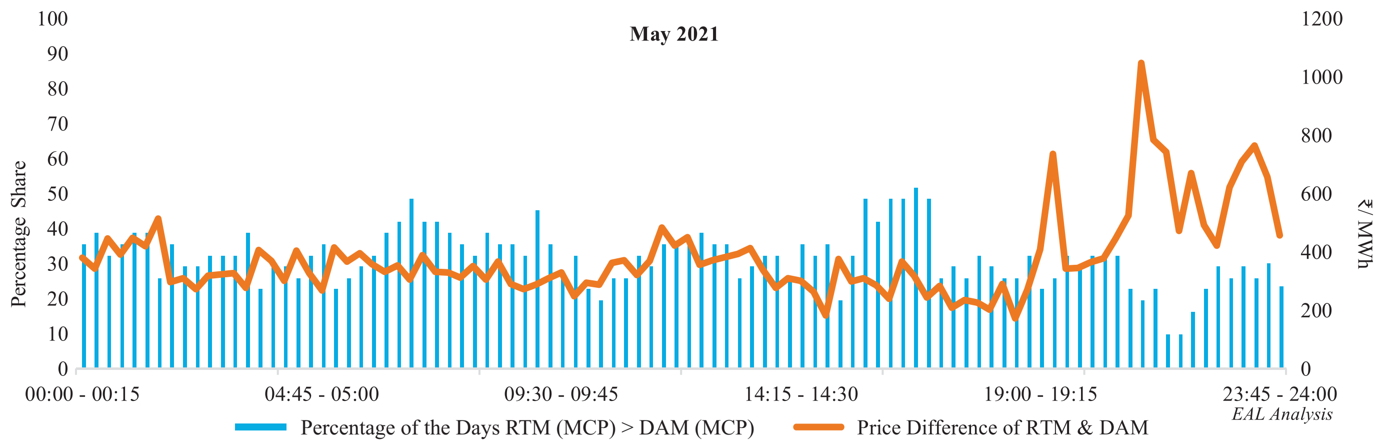


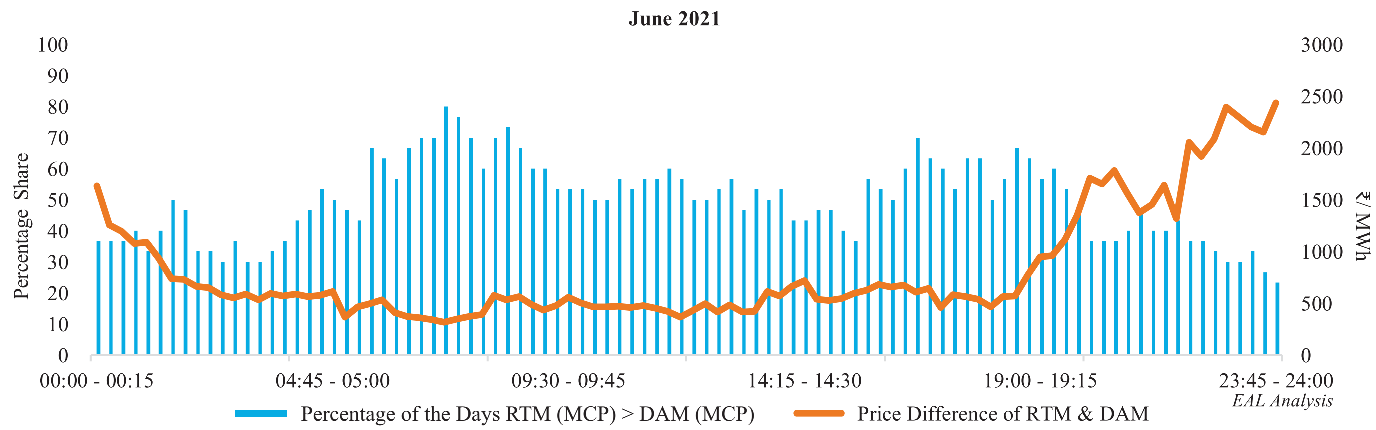
The weighted average clearing price of Non-Solar is higher in comparison to Solar in Day-Ahead transaction during April to June quarter. The proportion of sell and purchase bids in Solar is higher when compared to the bids placed in Non-Solar.

Note: The above power market overview and analysis are based on the data from IEX Website.

RTM Vs DAM on Market Clearing Price (MCP)







- The price difference between RTM and DAM is calculated only in cases where the former exceeds the latter. The block-wise RTM price exceeds the DAM price for about 36.73%, 31.60%, and 49.62% of the days for the month of April, May, and June, respectively.
- For block (07:00 - 07:15), 80% of the days in June, RTM prices surpass DAM prices.
- Maximum difference between RTM and DAM price was observed to be ₹ 2534.38/MWh (20:15 -20:30), ₹ 1047.13/MWh (21:00 - 21:15), and ₹ 2435.09/MWh (23:45 - 24:00) in April, May, and June, respectively.

Note: The above RTM vs DAM on MCP are based on the data obtained from IEX.

Energy Analytics Lab

Regulatory & Policy Perspective

CERC (Ancillary Service) Regulations, 2021 (Draft)

CERC released "CERC (Ancillary Service) Regulations, 2021 (Draft)" on 29th May, 2021 follow as:

Objective: To provide mechanisms for procuring, deploying, and paying for ancillary services, both through administered and market-based mechanisms, in order to keep the grid frequency close to 50 Hz, relieve congestion in the transmission network, and ensure smooth power system operation, grid safety and security. The mechanism of procurement, deployment and payment of secondary /tertiary reserve ancillary service is mentioned in Table 1.

Table 1: Mechanism of procurement, deployment and payment of SRAS and TRAS

Category	SRAS	TRAS
Eligibility for an SRAS/TRAS Provider	A generating station, energy storage and demand side resource connected to inter-or intra-state transmission system.	
	• Respond to SRAS signal within 30 seconds • Delivery obligation: 15 minutes • Sustain service at least for next 30 minutes • Generating station should be AGC-enabled • Provide minimum response of 1 MW	• Respond to TRAS signal within 15 minutes • Sustain service at least for next 60 minutes • Capable of varying its active power output based on instructions from Nodal Agency (NA)
Activation and Deployment of SRAS/TRAS	SRAS/TRAS shall be deployed by the NA on account of the following events including events specified in the Grid Code:	
	• After replenishment of primary reserves • If Area Control Error (ACE) > ±10 MW • NA may operate SRAS in tie-line bias, flat frequency or flat tie-line mode depending on grid requirements	• After replenishment of secondary reserve • If secondary reserve is deployed continuously in one direction for 15 minutes for more than 100 MW
Procurement of SRAS/TRAS	• On regional basis by NA • May follow market-based bidding mechanism • SRAS Provider shall declare their variable charge (VC) upfront on monthly basis • Availability of adequate reserves shall be determined by NA on day-ahead basis and on real-time basis before gate closure of RTM • SRAS providers cannot withdraw the standing consent without giving prior notice at least before 48 hours	• Buy Bid - Before the commencement of DAM/RTM, NA shall communicate the TRAS (Up/Down) requirement to the power exchange • Sell Bid - In DAM/RTM, bids must be provided for each time block/for a minimum of two consecutive time blocks. • For TRAS-Up/Down, Energy-Up/Down bid (₹/MWh) shall be submitted for the offer volume (MW) • Any TRAS Provider (cleared/not cleared/ not participated, in DAM) may place incremental bids in RTM
Selection of SRAS Providers and Price discovery of TRAS	• SRAS provider shall be selected by NA based on Custom Participation Factor (CPF) • CPF shall be computed based on Rate Participation Factor (Ramping capability in MW/min) and Cost Factor (VC or compensation charge) • Average of SRAS (Up/Down) data shall be calculated for every 5 minutes in absolute terms and used for payment of incentive as per Regulation 12 • Average of SRAS-Up/Down data shall be	• The principle of Uniform Market Clearing price and Pay-as-bid shall be followed for price discovery of TRAS–Up and TRAS-Down, respectively • The highest Energy-Up bid for TRAS-Up shall be MCP for Energy-Up in DAM or RTM • The Energy-Down bids shall be stacked from the highest to lowest Energy-Down bid and the NA shall select the TRAS-Down Providers in the same order • Provision for price cap for TRAS, if found

	calculated for every 15 minutes time block in MWh and used for payment of VC or compensation charge, to the SRAS Provider as per Regulation 11	necessary by the commission
Scheduling and Dispatch for SRAS/TRAS	• SRAS to be dispatched based on secondary control signals on regional basis • Secondary control signal shall be sent by NA to SRAS provider at the interval of 4 seconds • SRAS providers shall automatically follow the secondary control signal	• The schedule for TRAS shall become effective from the time block starting 15 minutes after issue of the despatch instruction by the NA • NA will issue dispatch instruction to all TRAS-Up Providers, when the actual requirement is equal to cleared volume in the market • When MCP-Energy-Up-DAM and MCP-Energy-Up-RTM are equal then, TRAS-Up will be dispatched on pro-rata basis. Otherwise, TRAS-Up shall be dispatched in accordance with ascending order of MCP-Energy-Up
Payment for SRAS and TRAS providers	• For SRAS-Up/Down, providers will be paid from/payback to the Deviation and Ancillary services pool account at the rate of their VC or compensation charge for 15 minute time block • SRAS Provider shall be eligible for performance-based incentive as per Regulation 12	• For TRAS-Up, provider shall receive MCP-Energy-Up, as discovered in the DAM or RTM for the quantum of energy instructed to be despatched by NA • Commitment charges at the rate of 10% of MCP Energy-Up-DAM or MCP-Energy-Up-RTM with a ceiling of 20 paise/ kWh for the quantum of energy not instructed to be despatched by NA • For TRAS-Down, payback to the Deviation and Ancillary Service Pool Account at the rate of their Energy-Down bid in DAM or RTM for the capacity instructed to be despatched by the NA
Accounting and Settlement of SRAS and TRAS	• The Regional Power Committee will account for SRAS on a weekly basis, based on SCADA data • The Deviation and Ancillary Service Pool Account shall be charged for the full cost including the (VC, Energy charge, compensation charge) of despatched SRAS-Up, for each time-block	• The Regional Power Committee will account for TRAS on weekly basis using interface meter data and schedules. • The Deviation and Ancillary Service Pool Account shall be charged for quantum cleared and dispatched and commitment charge for quantum cleared but not despatched
Failure in performance of SRAS Provider	• If the performance of SRAS Provider falls below 20% for two consecutive days, the NA may disqualify it for a week • Penalties shall be imposed to SRAS provider for violation of direction of the NA	
Shortfall in Procurement of SRAS and TRAS	• Those whose Unscheduled requisitioned surplus (URS) is despatched for TRAS-Up, in the event of short-fall in procurement of TRAS-Up through the Market, shall be paid at the rate of their variable charges for the quantum of TRAS-Up despatched • Those who are despatched for TRAS-Down, shall payback at the rate of their variable charges, corresponding to the quantum of TRAS-Down despatched	

EAL Opinion

- **Design of Market for Ancillary Services:** Ancillary services have a very important role to play in secure operation of a power system. Increasing share of variable renewable energy sources, demand further attention of system operator. Reserves Regulation Ancillary Services (RRAS) has played a key role in bringing stability in system frequency. However, current design of ancillary services does not incentivise fast response ancillary services, which is critical in operation of ancillary services with high VRE share. Furthermore, RRAS, in its current form, is also restrictive in terms of eligibility for participation.
- **Definition of Demand Response (Regulation 3 (1)):** The definition of demand response refers to the same being identified by the NA as per the system requirement. This might be construed to mean that the NA would identify demand response as one of the 'Supplier for ancillary services', whereas such specificity is not attached to other suppliers of ancillary services. Regulation should provide clarity with respect to the same.

  Further, variation in drawal by the control area should be attributable to demand response only if this is achieved through back-to-back volunteer demand reduction by the consumers, rather than load management/load shedding by the distribution company.
- **Define Demand Response Aggregator:** A 'demand response aggregator' should also be defined, and its role be specified in the definition of demand response.
- **Definition of Energy Storage (Regulation 3 (1n)):** The definition of Energy Storage may be modified as "Energy Storage in relation to the electricity system, means a facility where electrical energy is converted into any other form of energy which can be stored, and subsequently reconverted into electrical energy **which is injected back to the grid**".

  The text in bold should be added to bring clarity to the definition. Insertion of 'other' would ensure presence of an intermediate technology to convert conversion electricity to the other form. In the absence of stored energy being injected back to the grid (after accounting for conversion losses), storage would only behave as a load.
- **Definition and Computation of URS (Regulation 3 (1ae)):** URS means the surplus capacity of a generating plant that has not been requisitioned by the beneficiaries, and is available for despatch. It should be computed as the difference between the declared capacity of the generating station and its total schedule by the respective beneficiaries. This should, thus, be calculated 'prior to scheduling and despatch of the respective ancillary services'.
- **Eligibility for Demand Response an SRAS Provider (Regulation 7):** The eligibility for an SRAS provider, which especially mentions the eligibility for demand side resources, should enhance its ambit to include the 'demand response aggregators'. Which could be embedded within DISCOM and may not be 'connected' to the intra-state transmission system. In such cases, appropriate metering and communication requirement under the eligibility conditions may need to be fine-tuned to enable 'aggregated suppliers' of ancillary services with multiple metering locations.
- **Designing and Implementing a Demand Response Program:** In its true spirit, the demand response is a voluntary reduction in 'existing' demand of consumers, who have opted for the same. A reduction in 'demand' by load serving entities *i.e.* distribution licensees through load shedding should not qualify as demand response. To ensure effective participation of demand response, there is need to design and implement a demand response program with participation of aggregators, with adequate safeguards to ensure that the underlying rules encourage genuine demand response participation.

  A demand response aggregator can be included in the schedule of the respective SLDC as a virtual load/generator. The boundary for the demand response aggregator, covering identified loads (consumers), should have necessary metering and communication capability as defined in the eligibility conditions. The investment in such metering and communication capability can be justified under a business model for the demand response aggregator.
- **Selection of SRAS Providers and Despatch of SRAS (Regulation 10 (11)):** The average of SRAS-Up and SRAS-Down MW data shall be calculated for every 5 minutes time block in absolute terms for every SRAS Provider by the NA using the archived SCADA data at the NA. The"average of SRAS-Up and SRAS-Down" may be written as '5-min average of SRAS-Up and SRAS-Down' MW data to avoid the confusion.
- **Selection of SRAS Providers and Despatch of SRAS (Regulation 10 (12)):** The average of SRAS-Up and SRAS-Down MW data shall be calculated for every 15 minutes time block in MWh for every SRAS Provider by

the NA using the archived SCADA data at the NA. The "average of SRAS-Up and SRAS-Down" may be written as '15-min average of SRAS-Up and SRAS-Down' MW data to avoid the confusion.

- **Procurement of SRAS (Regulation 9 (5)):** It is not clear whether the participating generator need to declare their VC in line with the charge determined under either section 62 or approved under section 63, or they have liberty to quote at variance. In case such generators are allowed to quote higher than their VC, this will increase the supernormal profit for the sub-marginal plants (as discussed later in these comments).
- **Performance of SRAS Provider and Incentive (Regulation 12 (2)):** Incentive should be provided based on actual response against the secondary control signal 'SRAS-Up/Down' sent every 4 seconds to the control centre of the SRAS provider. However, the measurement of performance on the basis of 5-minute MW data as calculated in Regulation 10 (Clause 11) is not clear and needs to be further elaborated.
- **Performance of SRAS Provider and Incentive (Regulation 12 (3)):** The IEGC mandates the system constituents to follow the system operator's instructions. The draft regulation provides incentive on the basis of proportion of times an ancillary service provider responds to secondary control signal within the prescribed time limit. This incentive would be applicable for the overall energy 'delivered' by the ancillary service provider across the day.

  The scale of proposed incentive in draft regulation seems to be disproportionately high and will impose undue burden, particularly on distribution utilities. It is important to note that generators are already provided incentives for (i) Ramping related incentive, (ii) For peak and off peak hours corresponding to scheduled generation in excess of ex-bus energy @ 65 paise/kWh and @ 50 paise/kWh, respectively. Some of these existing incentives are themselves high and impose additional cost burden for the ultimate consumers. This issue has been highlighted earlier so in response to the relevant regulation/procedures.

  The proposed incentive going up to 40 paisa/kWh is disproportionately high and is not economically justified. An incentive of 10 paise/kWh to the entities meeting just 20% cases of response to the SRAS signal does not seem to encourage even minimal efficiency in performance as enshrined in the Electricity Act 2003. The scale of incentives should be replaced with a scheme of penalty and incentive. The former should be applicable for deficient response to SRAS signal below 80%, and a minimal incentive of 10 paise/kWh for performance beyond that (upto 95 %) and 15 paise/kWh for 95% and above.

  From point of view of total cost burden on ultimate consumers, incentive scheme should also be supplemented with penalty mechanism wherein performance below 45-70% band should be subjected to a penalty as suggested in Table 2.

Table 2: Incentive/ Penalty based on Performance

Actual performance vis-à-vis secondary control signal for an SRAS Provider	Proposed Incentive Rate (paise/kWh)	Suggested Incentive/ Penalty Rate (paise/kWh)
Above 95%	(+) 40	(+) 15
80 - 95 %	(+) 30	(+) 10
70 - 80 %	(+) 20	0
50 - 70 %	(+) 10	(-) 5
Below 50%	0	(-) 10

- **Procurement of TRAS (Regulation 16 (2a)):** The draft regulation seems to suggest that a separate market segment would be created for TRAS for a Day-Ahead and Real-Time basis. It needs to be clarified that Day-Ahead and RTM market do not refer to the existing contracts being traded on Power Exchanges. To bring about this clarity, the proposed two market contracts may be called as DAM-TRAS and RTM-TRAS, respectively.
- **Quantum of Requirement of SRAS and TRAS (Regulation 6 &16 (2a)):** Estimation of quantum of requirement for the SRAS or the TRAS close to the relevant time block as currently done in the case of RRAS would be a more meaningful exercise. In contrast, an estimation for TRAS on a day-ahead basis could not be undertaken reliably as system conditions are better understood close to the time block (especially due to variable renewable energy and demand variability) rather than on a day ahead basis. Furthermore, a day-ahead estimation of TRAS begins with a presumption of deviation greater than 100 MW. This is philosophically challenging as, under this regulation, the system operator is expected to 'estimate' possibility of such a deviation but not able to provide a framework to handle the same. This way, DAM-TRAS is proposed to work as a 'energy market' rather than ancillary services

market as such.

It is suggested that a phased implementation strategy be adopted wherein RTM-TRAS is implemented along with SRAS in the first phase. Introduction of DAM-TRAS would be relevant if the framework is not able to assure availability of the adequate resources at reasonable price as per the 'estimated' TRAS on RTM basis.

- **Price Discovery of TRAS (Regulation 17):** The uniform market-clearing price for TRAS-Up on the basis of an 'estimated' requirement is economically inefficient and also exposes the mechanism to potential gaming. The market-clearing price would be decided by the marginal plant (participant) as per the 'estimated' quantum of TRAS-up (See Fig. 1). This allows for significant supernormal profit to the sub-marginal plants (participants) (See Fig. 1). This is also unfair to the beneficiaries (particularly the consumer serving distribution utilities), who have paid the fixed charges of the generating plants. Hence, there is no under-recovery of fixed charges that needs compensation through a price over and above the variable charges.

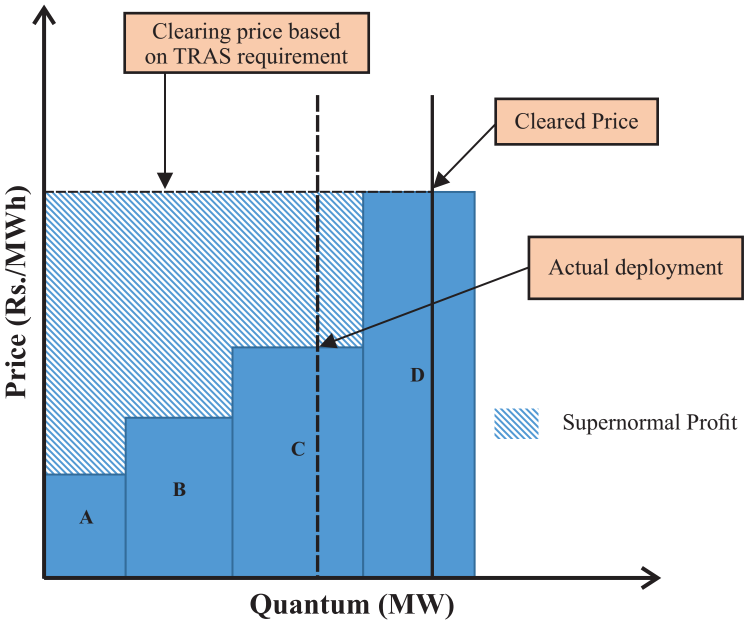


Fig. 1: Price discovery of TRAS-Up

Given that the existing generators will supply the TRAS-Up service from a capacity whose fixed charges are recovered under the prevailing tariff framework, any economic benefit that allows for recovery beyond the variable charges, and that too for a 'social good', would not be justified. Hence, pay-as-bid framework would be economically more efficient and fair mechanism for price discovery of TRAS-Up service.

- **The Time-line for Scheduling and Despatch (Regulation 18 (3)):** The draft regulation, while identifying timeline for activation of various ancillary services, does not seem to provide time required for data gathering from relevant telemetry, estimation of system parameters and decision making for activation, which may take few seconds to a minute. This would leave less than 15-minute of operational time for monitoring SRAS deployment and taking decision for subsequent SRAS/TRAS deployment. Accordingly, some of the suggested modifications include. “continuous deployment for 15 minutes” may be replaced with 'immediately succeeding block' so as to provide operational clarity as shown in Fig. 2 of the explanatory memorandum suggests that the TRAS deployment can be done within the 15-minute deployment period of SRAS, to ensure the decision to activate and deploy TRAS is taken after the 15 minutes' operation of SRAS (above 100 MW in one direction), the SRAS would still need to operate for another period of 15 minutes till the TRAS takes over. Hence, minimum operation time for SRAS, given the proposed condition in the draft regulation, would be 30 minutes. The timeline proposed in the draft regulation needs to be fine-tuned to ensure that it is consistent with the deployment

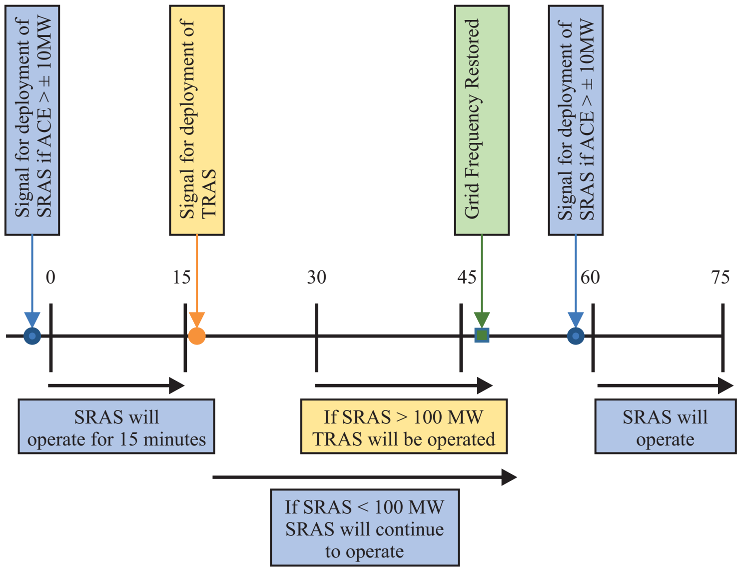


Fig. 2: Timeline for SRAS and TRAS operation

process mentioned elsewhere in the regulation.

- **Differentiate Between Reduction in SRAS/TRAS Deployment vs SRAS/TRAS Down:** Once SRAS/TRAS (Up/Down) is deployed, the system conditions may necessitate reassessment of the SRAS/ TRAS requirement. This should first be reflected in a reduction in the currently deployed Up (Down) service in the descending order of their VC/ MCP rather than a simultaneous deployment of Down (Up) service. Although the regulation's intent may be same, it should be clearly reflected in the regulation.
- **Shortfall in Procurement of SRAS and TRAS or Emergency Condition (Regulation 20 (1)):** For the purpose of calculating the incentives to be paid for RRAS Up/Down regulation under emergency/shortfall (Regulation 20 (1)). The proposal for incentive to respond to an emergency call would be much more justified than the one proposed in the Regulation 12 (3).
- **Proposed Methodology for Calculation of Allocation of Secondary Control Signal among SRAS-Up Providers (Regulation 10 (5)):** The process of evaluating the rate factor and cost factor does not provide adequate incentive to the eligible entities who can deploy the required ancillary services at a relatively faster rate, which are more relevant in the context of higher VRE share. In this draft regulation, the participation factor is evaluated using the rate factor which is based on absolute ramp rate. As per EAL opinion, instead of using the rate factor based on absolute ramp rate, use of percentage ramp rate would provide a more robust estimation of the participation factor. We suggest modification to include ramping rate (in %) rather than in absolute term (MW/min) to provide correct incentive for the same.

MoP Discussion Paper on Market Based Economic Dispatch (MBED)

Ministry of Power issued a discussion paper on 1st June, 2021 on "Market based Economic Dispatch (MBED)". The key highlights of the discussion paper are summarized below.

Summary of key points of the discussion paper

The objective of proposed MBED mechanism is to ensure the optimization of cost by optimal scheduling and dispatch from all station based on Market-based dispatch principle. It will also encourage efficient generation capacity addition in the future through Uniform pricing framework.

Table 3: Potential advantages of MBED for stakeholders

Particulars	Benefits
DISCOMs	• Boosts the utilisation of low-cost generators • DISCOMs would receive a portion of the additional market revenue due to utilisation of low-cost generators • The overall procurement cost will be reduced
Generators	• Cheaper plants will be fully utilized • Reduction in coal transportation costs as pit-head plants will be utilised to its full capacity • Additional Revenues will be provided to generators for selling URS power
Others	• The demand for reserves (Ancillary Services) might be appropriately assessed • Expansion of the balance area from the state to the national level that would result in better RE integration and reduced RE curtailment • MoD would be more systematic • System marginal price would be much more transparent • The proposed MBED mechanism would be key step in enabling uniform clearing price for procurement of power

Table 4: The key differences between Security Constraints Economic Despatch (SCED) and MBED

Energy Analytics Lab

Parameters	SCED	MBED
Operating mode	Administrated by POSOCO	Market-based
Time Frame	Initiated after ISGS's Right to Revision of schedule ends and final schedules are prepared	Designed to be deployed after DISCOMs release Day-Ahead schedules and generators provide their capacity to the market
Objective	Assures system cost optimization for the share of demand contracted from ISGS and other associated regulated generators with implementation of optimum generation schedule while considering ramp and technical minima constraints	Expensive plants may not get cleared as MBED doesn't ensure unit commitment Uniform system marginal prices will establish the basis for market-based generation capacity additions in the future

Table 5: Key changes in procurement of power and scheduling for introduction of MBED framework for NTPC thermal stations

	Parameters	MBED
Scheduling mechanism	• The DISCOMs schedule the NTPC generators as per their entitlement and reach out the Power Exchanges (PX's) to meet the remaining electricity demand • As DISCOMs are unsure of cheaper alternatives outside the states, hence many low-cost generation capacities are partially or sub-optimally utilized • During off-peak hours, DISCOMs tend to run expensive generation capacity at its technical minimum, even at the cost of limiting the output of cheaper generation	• DISCOMs can still schedule generators themselves, although both DISCOMs and generators must bid in DAM • The amount of power that is self-scheduled would be taken into consideration while settling bilateral contracts • The entire demand shall be met by dispatching the least-cost generation mix from NTPC plants while maintaining grid security • NTPC stations that are less expensive will be dispatched to the largest extent possible, whereas more expensive will run optimally as per the requirement
Schedule revision	• Generators and DISCOMs can revise their schedules before 7/8-time blocks without any financial liability	• Till the results of the DAM are disclosed, there will be no RTR for the NTPC plants • Beneficiaries can also take part in the RTM and fine tune their Day-Ahead positions properly
Action by buyers, sellers and PXs	• Generator's self-scheduling by DISCOMs results in a sub-optimal MoD for scheduling and dispatch • In this mechanism, the true marginal cost would never get discovered	• Generators must bid in DAM based on their own Energy Charge Rate (ECR), with no changes for fuel and other charge in the future • A national MoD will be formed and subsequently dispatch all generators • The market clearing engine of PX's will schedule the generating units based on optimal dispatch principles, once the bids and offers are submitted
Payment and settlement	• DISCOMs pay the variable charges to scheduled generators based on the quantum of energy scheduled • URS power can be used by a DISCOM that is not the original beneficiary of the generators, after exhausting their contracted power in such ISGSs • Such beneficiaries would bear the fixed cost liability for URS scheduled instead of the original beneficiaries	• DISCOMs/buyers will pay the market operator at MCP for the Day-Ahead demand • Generators will be paid at the MCP based on the execution of their selected bids • Under long-term agreements, buyers will be refunded the difference between MCP and the contracted price based on the quantum of power self-scheduled via Bilateral Contract Settlement (BCS) • The net revenue earned by NTPC generators from URS will be shared equally with the concerned beneficiaries subject to a ceiling of ₹ 7 paise/unit
	• NTPC generators with long-term PPA are paid for the fixed cost separately outside the market	

Table 6: Working capital management for stakeholders

Stakeholder	Benefits
Generators	Ensures payment as per the rules of PXs
DISCOMs	Provides necessary support with the time frame (within 45-60 days from the date of disbursement) to repay back the amount to designated agencies
Exchange	Addresses counterparty risk of exchanges
Sponsoring Agencies	Agencies like PFC/REC provides room to increase their loanable quota and revenues from power market

EAL Opinion

- **Relevance of MBED:** Experience with short-term power market development provides a test case for the maturity of the sector to adopt such a change, and the preparedness of most of the stakeholders to participate in the same. However, the experience varies across states in terms of the avenues for optimisation and the ability of the available practices and tools to do so.

  It is also important to mention that the current market design provides for voluntary participation. MBED is a departure from the same as it entails broader participation across the distribution utilities.

  As per EAL opinion, competition for fixed charges should be through capacity market while competition on variable charges through MBED.

- **SCED vs MBED:** SCED optimises power procurement fro m eligible ISGSs. **MBED, if implemented only for the eligible NTPC generators (as proposed), the gains (in terms of optimised cost of power procurement) would be limited and may be of similar order as in the case of SCED.** Without participation of intra-state generators, true gains of MBED would not be realised.

- **Gate Closure and Right to Recall:** MBED, implemented on a Day-Ahead basis would require the utilities to forego 'right to recall'. Post submission of the bids to MBED (*i.e.*, at gate closure), the generators as well as the DISCOMs commit themselves to sell/buy the cleared quantity. **This loss of flexibility (associated with 'right to recall') to the distribution utilities is of value on account of the uncertainty associated with demand as well as RE generation forecast.**

  Under MBED, DISCOMs can rebalance their portfolio in the Real Time Market (RTM). Depending on the market conditions and the need to buy/sell, the DISCOMs would have to bear the additional burden due to rebalancing of their portfolio.

- **Long-term Impact on Investment and Need for Capacity Market:** MBED is designed as an energy market, wherein existing beneficiaries of the PPAs continue to pay the associated capacity charges. The market participants, procuring energy through the MBED platform, only bear the market clearing price associated with such capacities. This does not provide an incentive for signing long-term PPAs tied up to payment of such fixed (capacity) charges.

  To ensure that adequate investment is undertaken to maintain resource adequacy in the system, **MBED should be supplemented with a capacity market.** Design of such a capacity market would need to take into account a reasonable estimate of resource adequacy that needs to be tied up with the existing consumer base of the load serving entities, as well as other entities (for *e.g.,* large consumers) who would be eligible to directly participate in the MBED in the near future.

- **Generator's Bid and Variable charges and flexibility thereof: The generators, whose tariff is regulated u/s 62 of the Electricity Act 2003 should bid at their variable charge.** Given the adopted price discovery mechanism, *i.e.* the uniform market price, the marginal generator would dictate the market clearing price in MBED to ensure efficient price discovery in MBED, wherein the generators should be close to their marginal cost, the generators with regulated tariff should therefore bid at their variable charge or below. This will ensure that a higher bid by such marginal plants do not dictate the market clearing price, and hence increase the overall burden for distribution utilities, and hence the end consumers.

- **Margin on Sale of Un-Requisitioned Surplus (URS):** Any benefit arising out of sale of URS above their variable charge is proposed to be shared between the two entities in a 50:50 ratio with a limit of 7 p/kWh for the generators.

In the absence of any demand, commercial or payment risk, the suggested ceiling of 7 paise/kWh on the sale of URS power is significantly high. On the contrary, the demand risk associated due to 'right to recall' till the SCED gate closure, available at present, will also be negated by MBED. Now the MBED 'schedule' would have greater certainty for the generators. It is also important to note that there is no commercial risk to be borne by the generators as the associated fixed charges (as per the existing regulatory framework) would be paid by the respective beneficiary. The 'margin' on sale of URS power is an additional income for which no additional risk is involved. Furthermore, the payment risk associated with sale of this power is nil as all the URS power sold through a MBED market platform, which would have an inbuilt payment security mechanism requiring advance payment/margin money. (Section 2)

The 'margin' for sale of URS by generators (under MBED) cannot at all be compared with the 'trading margin' limit of 7 paise/kWh for the licensed traders, who are exposed to comparatively much higher risk. It is also worth noting that the 'actual' trading margin is generally less than 7 paise/kWh. The trading licensees are allowed to charge trading margin up to 7 paise/kWh. Against this, the actual weighted average trading margin charged by the trading licensees during 2019-20 was only 3.1 paise/kWh. The trading margin recorded during Jan-Mar 2021 was 2.1-2.5 paise/ kWh. **It is clear that the proposed 'margin' limit of 7 paise/kWh on sale of URS under MBED is very high, and should be appropriately revised. This should be limited only to compensate the generators against the 'additional risks' over and above the prevailing tariff and, scheduling and despatch framework.**

- **Optimal Operation of Generation Assets:** MBED, in its current proposed form, provides an opportunity to optimise cost of power procurement for the buyers but does not provide a similar opportunity to the generators. Post-MBED market clearing, opportunities on account of cumulative supply obligation (*e.g.*, due to participation in RTM) and certain (eligible) technical constraints may present an opportunity for the generation companies to operationally optimise generation across co-located units, and even other generation assets subject to transmission availability. Any gains arising out of such operational optimisation should be shared amongst the generators and the beneficiaries with proportionately larger share of gains for the generators.

- **Price Coupling of Multiple Power Exchanges:** The regulatory framework for power market development in the country provides for multiple power exchanges. The contracts traded on the power exchanges are open for voluntary participation. In contrast, MBED mandates participation for the identified buyers and sellers.

  In this context, operation of multiple power exchanges for a 'theoretically' unified market platform would present a few economic challenges. Price coupling of multiple power exchanges may seem to be a plausible solution but may present relative disadvantage to the incumbent and dominant PXs, who may have a larger clientele base. It is important to highlight that price coupling is being suggested for a 'new market' segment rather than an existing one. The proposed alternate solution wherein 'corresponding buyers and sellers choose to participate in a (emphasis added) power exchange' would dimmish the very basis of MBED as differentiated bids would now have limited opportunity to compete with each other. Further, this would also skew the economics of URS power that would be sold through the PXs.

  It is suggested that a modified form of 'bid allocation' mechanism be adopted wherein instead of horizontal segregation of pair of buy-sell bids, it may be segregated vertically to allow competing bids to appear on all the PXs. This, being a sub-optimal solution, may need to be revisited with an assessment of the market outcome within 4-6 months.

Table 7: 'Choice' of PX platform for buy-sell contract pairs (MBED proposal)

		PX 1	PX 2	PX 3
G1-D1	100	100		
G2-D2	200		200	
G3-D3	60			60

Table 8: 'Sharing' of buy-sell contract pairs across PXs (suggested alternative)

		PX 1	PX 2	PX 3
G1-D1	100	40	40	20
G2-D2	200	100	40	60
G3-D3	60	20	20	20

Note: The pair of buyer-sellers should ensure that same quantity of buy as well as sell bids are placed on the respective PXs.

The basis of 'allocating' share of buy-sell pair of contracts may be decided by the corresponding parties. However, it would be beneficial for the sector if the stakeholders are able to evolve a fair and dynamic basis for such allocation while ensuring that economic efficiency as well as oversight over market power is not compromised.

- **Need for a Comprehensive Market Monitoring Framework:** The Electricity Act 2003 empowers the CERC to monitor power market and ensure that unwarranted market behaviour does lead to an economically adverse outcome for the market. The existing framework for 'market monitoring' needs to be enhanced to enable CERC to effectively monitor market behaviour of buyers/sellers on alternate contracts across the market platforms.

- **MoD vs MBED - Impact of Transmission Charges and Transmission Losses:** MoD principle adopted by the respective distribution utility takes into account, amongst other factors, the associated transmission charges and transmission losses. In contrast, price discovery in MBED would not take into account the associated transmission charges and transmission losses. MBED, in general, would enhance schedule of pit-head based generators at the cost of those near the load centres. This would have a resultant impact on utilisation of transmission assets, and also place greater demand for transmission investment to support additional flow of power from pit-head stations to load centres. The resultant cost of the cheaper power to a beneficiary state may either reduce the overall benefits of MBED. **An interim analysis of the MBED considering the overall incident of all charges should be undertaken to identify the scale of impact of such clearing mechanism.**

  It will also be useful to clarify, if the simulation presented in the discussion paper took into account the transmission charges and transmission losses.

- **Treatment of Part Load Compensation and Incentives/Penalty:** In case of generator, which was not earlier scheduled and was rather placed under reserve shutdown by the respective beneficiary, gets a part load schedule under the MBED, the burden of part load compensation would be due on the original beneficiary of the PPA. The following specific charges/incentive/penalty applicable under the prevailing regulatory framework for tariff,

  - Compensation Part load operation
  - Incentive structure for higher availability during the peak/off-peak hours
  - Incentive/penalty for demonstrating/failure to demonstrate ramping capability of the generating plants

  Some of the generating plants, particularly those with low VC, would see a reduction in Part load compensation as their schedule would increase.

  These issues may present a legal as well as a regulatory challenge if the distributional impact of such cost components places significant impact on the buyers. These regulatory issues can be addressed if the incentive/penalty framework is integrated with the market (and some may need to be discontinued) rather than the same being implemented through individual regulations.

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