Comments on CERC's staff paper on power market pricing
Submissions of the Council on Energy, Environment and Water

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Electricity markets globally are seeing elevated prices, and regulators and policymakers have responded to contain the impact on electricity consumers. India, too has witnessed multiple periods of extremely high prices on its power exchanges (PX) in the last year, specifically in October 2021 and March-June 2022. The CERC's staff paper on power market pricing explores options to deal with such price spikes and raises some important points for discussion. Our responses to these questions are summarised here, and detailed comments are provided in the Annexure.

Does the pricing methodology need a change?
We understand that the pricing methodology does not require a change as of now. Based on the available information on the market performance, we believe that the uniform market clearing price (UMCP) mechanism continues to work in the way in which it is intended, i.e. discovering the marginal cost of production, incentivising supply based on true marginal cost, and providing opportunities to earn profits during scarcity. The main causes for the observed price spikes lie outside the pricing mechanism, and so should the interventions to mitigate its undesirable impacts.

What should be the criteria for regulatory interventions? How do we address the negative impacts of a price cap?
The regulator needs clear policy objectives to intervene in the market and design the interventions expressly to meet these objectives. For example, if the excessive revenue of generators during distress periods is a concern, the regulator could address it through a revenue cap-and-sharing mechanism. Closer monitoring of the costs of generators and the bidding behaviour of buyers is needed to keep speculative bidding on the PX in check and maintain market efficiency. The costs of administering any regulatory intervention in the market must be carefully and realistically considered. Further, there are other options through which discoms can hedge against price spikes, like forward contracts, financial contracts, etc. The implementation of these instruments should be expedited.

What should be the appropriate market structure/design to encourage flexible resources like Demand Response and ESS?
The market segment for flexibility resources needs to be clearly defined. DR/ESS can be aggregated to provide secondary or tertiary ancillary services in the ancillary services market. As flexible resources must react quickly to price signals, incentives to invest in such resources need to be given. A two-part tariff for these resources could help, where capacity charges are paid to keep the capacity available and energy charges to cover the operational cost. The compensation could be given under the 'uniform clearing price' mechanism, with the cheapest capacity bids selected first. The energy prices can also be considered with a lower weight to avoid speculation i.e., bids with very high energy prices get refused even if the quoted capacity charges are very low.

Our endeavour via this submission is to share ideas to improve the efficiency of the power market. We would be happy to provide further clarification to the CERC on any of the submitted comments if needed.

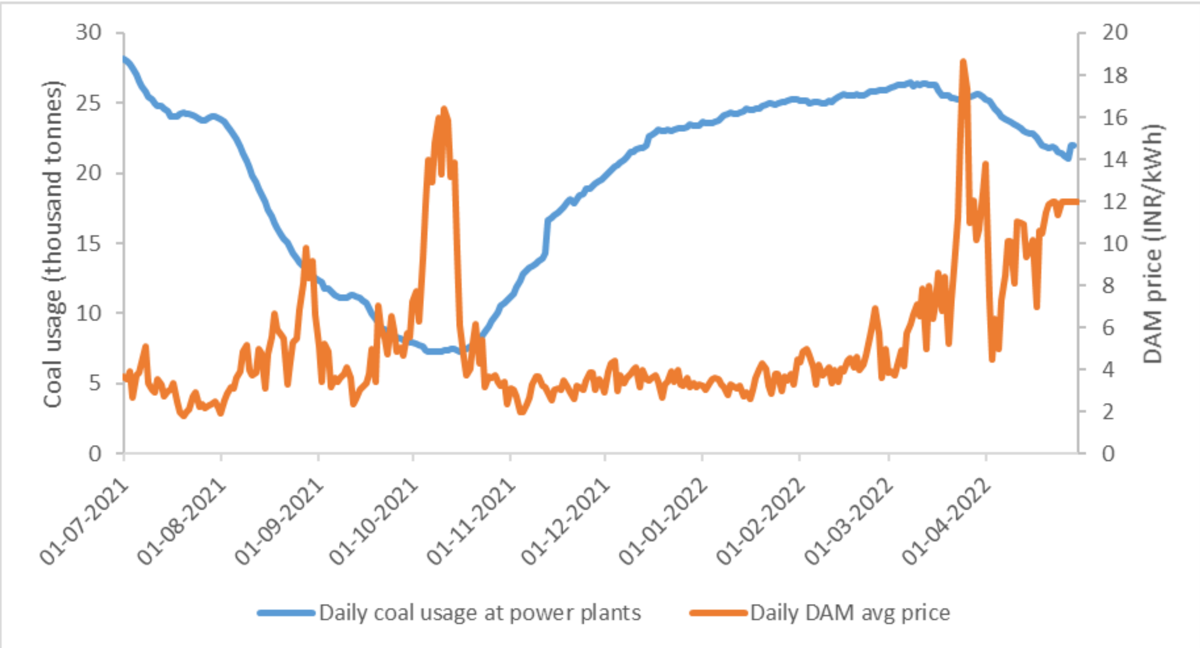
Annexure: Detailed comments and rationale

1. Does the pricing methodology need a change?

The current pricing methodology is based on the principle of maximising social surplus, i.e., the sum of buyer and seller surplus. When the equilibrium or clearing price is low, a chunk of the sell offers in the market that are higher than the clearing price will not get dispatched. For instance, as per the Monthly Report on Short-Term Transactions in Electricity for January 2020, the volume of sell bids was 11,800 MUs, while the buy bids added up to only 5720 MUs, and the total cleared volume was about 4,792 Mus and the maximum clearing price was only INR 5.00/kWh. This demonstrates excess supply, resulting in many sellers getting 'bid out' of the market. However, prices can see a spike when supply is scarce relative to demand (such as in October 2021 and March 2022) or when market participants exercise market power, such as by withholding capacity.

In October 2021, the major reasons for the supply shortage were an extended monsoon, the generators' failure to foresee the surge in power demand, and a shortage of rakes to transport fuel to power generators via rail (figure 1). In March 2022, the causes of the price spike were an early summer and unforeseen demand for power, which the discoms could not forecast, in addition to continued coal stocking issues and extremely high fuel prices in the international market. Hence, based on the available information, we conclude that the price spikes were a result of normal market operation, with no evidence of anti-competitive behaviour or exercise of market power.

Figure 1: The causes of price spikes on the PX in October 2021 and March 2022 were different



Source: CEEW analysis based on coal usage data from CEA and MCP data from IEX
Note: DAM = Day-Ahead Market

However, can the adverse impacts of the price spikes be mitigated by changing the price discovery mechanism, and do better alternatives to the UMCP exist? The core issue appears to be that under the current pricing regime and given the external conditions, the market price is set by the marginal (most expensive) plant required to meet the demand, leading to high prices for all buyers. The alternative discussed in the staff paper is the pay-as-bid (PAB) mechanism.

As highlighted in the staff paper, if the bid volumes and prices by sellers are the same under both mechanisms, the total cost for meeting demand under PAB would be lower than UMCP. This is demonstrated through a simple analysis of total costs between the two mechanisms using actual timeblock-level aggregate supply and demand curves for DAM (table 1). For two timeblocks on 31 October 2021, the total cost for the cleared volume under the hypothetical PAB regime would be 27 per cent lower than the actual total cost.[1] In situations of greater scarcity, the difference between the two methodologies would increase. On 26 March 2022, when the clearing prices in DAM were higher, the total cost for the cleared volume under PAB would be 42 per cent and 52 per cent lower than the actual total costs in off-peak and peak hours, respectively.

Table 1: Total cost for the cleared volume in DAM under the UMCP is higher than the PAB mechanism

Date	Timeblock	Cleared volume (MWh)	Clearing Price (INR/MWh)	Total cost under UMCP (INR)	Total cost under PAB (INR)	PAB costs lower than actual costs
31 October 2021	1300-1315	4,648	1,000	46,47,925	33,70,508	27%
31 October 2021	1900-1915	19,855	3,150	6,25,43,643	4,56,40,579	27%
26 March 2022	1300-1315	25,556	10,000	25,55,59,750	14,87,00,805	42%
26 March 2022	1900-1915	37,527	20,000	75,05,30,500	35,69,47,149	52%

Source: CEEW analysis based on data extracted from demand and supply curves on IEX

However, the assumption of consistent bidding behaviour in the two mechanisms may be unfounded. Mount et al. (2001) show that after the initial trading periods, as market participants get more information on the expected clearing price, the range of bids under PAB tends to be lower than in UMCP, leading to a flatter supply curve, higher average prices and precluding demand response. This results from suppliers bidding close to the expected clearing price rather than their true marginal costs due to the risk of non-recovery of fixed costs. This is the opposite outcome of UMCP, where sellers have the incentive to maximise the difference between their bid and the market clearing price. A panel set up after the high-price events in California in 2001 concluded that this change in bidding behaviour in moving from UMCP to PAB would nullify any perceived benefits and lead to lower investments in new capacity and demand response (Kahn et al. 2001). Skewed incentives under PAB may lead to cheaper (more thermally efficient) plants getting undercut by costlier plants when information asymmetries exist between generators, leading to system-level inefficiencies (Abbink, Brandts, and McDaniel 2003).

The realistic assumption of information asymmetry between generators on demand and expected clearing price is important. By withholding capacity under UMCP, large generators stand to gain under

[1] Here we assume that sellers would bid as per their true marginal cost even in the PAB mechanism, an assumption that we discuss in subsequent paragraphs.

certain conditions, while under PAB, this proposition is much riskier since the losses would be larger if the bids prove to be higher than the clearing price. However, under PAB, larger generators may also be better positioned to know the periods in which capacity will be withheld and, over time, the expected outcome of such withholding. Indeed, PAB leads to lower prices and volatility in studies which do not allow for market power or information asymmetries (Xiong, Okuma, and Fujita 2004).

In the Indian context, fixed costs for most thermal power plants are paid by off-takers under long-term power purchase agreements (PPAs) as availability-based charges, energy is sold on the PX only after obtaining permission from the off-takers, and the profits are shared. This potentially builds a case in favour of paying generators only the marginal cost under PAB since fixed cost recovery is assured outside the market, and they do not have to rely on mark-ups under UMCP.

However, there are three drawbacks of this argument: 1) in such a scenario, the CERC would have to closely monitor the bidding behaviour of generators to make sure that they are bidding based on true marginal cost, 2) a revenue stream for discoms from selling surplus generation on the market would be cut off, and 3) given that there would be no opportunity to earn profits, generators may not participate in the market at all and the utilisation of diversity to reduce system-level costs will not be possible.

Thus, implementing PAB could have several negative implications:

1. Higher dispatch schedules for inefficient plants and those with higher variable costs,
2. Distorted signals on the value of demand response,
3. Increased burden on the regulators to monitor bidding behaviour and marginal costs,
4. Lower utilisation of system diversity, leading to higher total costs of dispatch, and
5. Reduced opportunities for discoms and generators to earn revenue by utilising surplus capacity.

2. What should be the criteria for regulatory interventions?

In Australia, the EU, and the US, most power purchases occur over the organised wholesale markets as opposed to 10-12 per cent in India. Hence, regulators have developed tools to limit financial risks and exposure to prolonged stress (price caps triggered by force majeure events, VoLL, cumulative price thresholds) (AEMC Reliability Panel 2008). Hogan (2017) discusses an administrative reserve shortage pricing mechanism which kicks in during shortage events. In this mechanism, the prices are set considering the value of the reserve requirement for the system operator and adjusting the market prices to reflect such value. This pricing mechanism fully reflects the cost of meeting the demand and ensuring system reliability. Automatic mitigation measures and the thresholds are discussed by Lesieutre et al. (2004) and by Kiesling and Wilson (2005), and they note the technical issues and judgments that are made in determining the reference levels.

A price cap with a subsidiary objective of reducing price shocks for end consumers tends to distort the market (Simshauser 2014). An effective price cap should be such that new investment in generation is not disincentivised and resource adequacy is maintained. One of the tools to determine this is the Value of Lost Load (VoLL) (Joskow 2019).[2] VoLL is assessed based on the value of electricity consumption for residential customers assessed through surveys, the value of lost business and foregone production and lost sales for commercial and industrial customers, and estimates from past black-outs or brown-outs and the production function (Tol 2007; Bodell 2017).

[2] Methods to calculate price caps are discussed by Simshauser (2014).

Emergency situations should be defined with clear-cut policy objectives.[3] The Staff Paper refers to examples of the Australian and the European Union (EU) markets, where emergency situations are leading to regulatory interventions. In the EU's context, sustained high prices and the consequent impact on households and industry have led to the intervention by the European Commission (and not the system operator or the market regulator) (European Commission 2021). An emergency situation due to external factors must be distinguished from the normal market operation that reflects supply scarcity.

Additionally, the context of these emergency tools for other markets needs to be kept in mind. These are values that are set based on pre-identified methodologies and are periodically reviewed. Indian regulators must consider the cost and benefit of spending resources in defining these values where the short-term market is not as deep. In some cases, the direct administrative costs of regulation may approach or outweigh the potential gain in social welfare.

Hence, the criteria for the regulatory intervention depends on the objective sought to be achieved. It may not be possible to set metrics for normal market operations and define thresholds for regulatory interventions without pre-defined objectives. The scope for when the CERC oversight of the market appears to be limited to ensuring fair and competitive market operations and addressing abnormal price and volume behaviours (Regulation 48-51 of the CERC (Power Market) Regulation, 2021. Mitigating consumer hardship is as yet outside the purview of CERC.

Defining a tolerance level for price caps requires a clear understanding of the causes of price spikes and their impact on buyers and sellers, based on which an efficient price cap and tolerance levels can be defined. The level of a price cap and the tolerance band for reaching it needs careful consideration. From the perspective of the generators, a price cap and tolerance level that is too low can hinder their ability to supply power if fuel costs are actually high.[4]

The Staff Paper expresses concerns that inframarginal generators are making supernormal profits. However, this needs further substantiation on the following counts:

1. Nature of inframarginal generators: We need additional data on the kinds of generators participating in the market and their typical supply bids and quantities against the market clearing price. It is uncertain whether there is a clear demarcation of generators, their marginal cost, and the load they serve.[5] Further, separate market segments have been defined for RE, which can have a separate price cap. Further comments on this are provided in 3.1.
2. Whether there is anti-competitive behaviour by generators which are utilising the scarcity situation and selling at higher prices. Anecdotally, we understand that this is not the case in India.
3. The actual impact of the price spikes on discom and end consumer finances. Buyers typically procure only marginal, or peak load from the short-term market since 80-90 per cent of the requirement is met through long-term contracts. The scale of the financial impact of these

[3] Policy objectives could be ensuring system reliability, protecting discoms from price shocks, or maintaining competitiveness of the market (Lesieutre, Goldman, and Bartholomew 2004). The emergency measure triggers and the responses will change based on what the policy objective would be.

[4] Indian regulators do not have the burden of assessing the VoLL and the most efficient price signal for new investment since investment decisions for new generation capacity are not dependent on the short-term market. New investment, in both conventional and non-conventional energy, is still exclusively reliant on long-term purchase agreements.

[5] In power market operations, inframarginal generators normally receive revenues that exceed their marginal cost of operation, which is required to incentivise investment in new generation. Further, the inframarginal and mid-merit generators that serve the base load and the supramarginal generators that serve the peak load are typically segregated according to fuel types and technology. Such a distinction is not made for plants in the Indian market.

purchases on retail tariffs and discom finances is not fully assessed. In case there is substantial financial impact and consequent load shedding due to these price spikes, then the policy question of "how much should discoms spend on short-term purchases?" would determine the tolerance level for a defined price cap. State Electricity Regulatory Commissions (SERCs) must allow legitimate short-term purchases by discoms. Currently, short-term purchases are allowed but with limits on the price at which the purchases can be made. Extreme price events that are not caused by a market failure must also be considered and allowed by SERCs. High prices have also led discoms to improve load forecasting and resource adequacy assessments. Any market intervention that cushions the impacts of high prices will not lead to these positive outcomes.

2.4. Any other suggestions?

It is important to separate the different points: 1) fundamentally, the market design problem is how to dispatch different technologies optimally, and 2) whether short-term markets signal enough long-term investment. The question of PAB vs UMCP is relevant to the problem of which system more optimally dispatches different kinds of generators. High gas prices due to geopolitical reasons reignited this debate in the EU. The gas and electricity prices are coupled because gas is typically the price-setting generator. In India's case, we need closer monitoring of the kind of generators that impact the market in different operating conditions and in what way.

Other questions that need to be disentangled from the above are:

1) What should be the mechanisms to incentivise investments in generation capacity? In this context, how can the VoLL be calculated to set price caps in the short-term market?
2) How does the integration of RE impact short-term dispatch and long-term investment signals? A high-RE scenario incentivises generators that have high flexibility. The emerging picture is that long-term signalling and short-term dispatch will have to be separate.
3) What are emergency situations, and what can regulatory responses be? Regulatory responses for each may be different. For example, plants going into outages may lead to unusually high prices, triggering an emergency situation.

3. How do we address the negative impacts of price caps?

3.1. What should be the basis for defining supramarginal or high-cost generators? Technology or fuel source?

From stakeholder consultations, we know that a major reason for the clearing price to hit the cap may be speculative bidding by buyers and sellers, i.e., discoms may submit a bid for INR 20/kWh so that their requirement is more likely to be met in the market, even if it does not reflect their true ability to pay. Simultaneously, if sellers also offer INR 20/kWh in the expectation that at least one buyer would bid at that amount, even though their true marginal cost is much lower, the clearing price may touch the cap.[6] Hence, the first step must be to monitor that generators, regardless of the kind of fuel being used, bid only based on their true marginal costs.

Second, a range of variable costs may exist for the same fuel as the marginal cost of generation is determined not just by the type of fuel but also its quality, its geographical distance from the plant, the mode of procurement (e.g., open market vs long-term linkages), and whether it is domestic or imported. For example, prices of imported coal skyrocketed in March 2022 due to a shortage in the international market, due to which power plants running on imported coal witnessed a steep rise in

[6] In the absence of detailed bid and sell data, it is impossible to independently verify that such behaviour is indeed taking place.

production costs. As fuel prices are influenced by many factors, including the international market, the price of electricity generated from different fuels may become similar in certain situations. Hence, in the absence of clearly defined roles for plants operating on different fuels (such as base load vs peaking plants), a distinction based only on fuel will not correctly identify supramarginal generators.

If at all supramarginal generators need to be identified, it may be done based on a combination of fuel and plant efficiency, i.e., the amount of fuel used per unit of electricity produced. Plants with lower thermal efficiency but lower costs due to other factors may be placed higher in the stack so that they are dispatched only in high-price/scarcity situations, ensuring a lower emissions dispatch and efficient use of the scarce fuel. The due diligence for such stacking may be conducted periodically (annually or every 2-3 years) by CERC along with the SERCs for all thermal plants. Further, the computation of any threshold should clarify the treatment of transmission charges since they are also passed on to consumers, i.e., would generators with low variable costs become supramarginal after the addition of regional/state transmission charges?

3.2. Would there be enough liquidity in this small segment for collective transactions (demand and supply curve intersection) to take place? Would it lead to market power by these small sets of generators?

Table 2 shows that following the lowering of the price cap from INR 20/kWh to INR 12/kWh in April 2022, the clearing prices eased by May. As scarcity subsides, the demand for high-priced power will reduce. In the case of the spike in April 2022, clearing prices also reduced as measures were taken by the Government of India to soften coal prices, such as mandatory blending of imported coal. Thus, enough liquidity to ensure a permanent high-priced market segment may not be present, although it can be a temporary measure in scarcity situations. Alternatively, a two-stage bidding process may be considered in temporary situations where high-priced generators are cleared in a two-step process.

Table 2: Heat map of timeblocks where MCP was equal to or above INR 12/kWh

Month	Total number of time blocks	Time blocks where RTM MCP was above INR 12000/MWh	Time blocks where DAM MCP was above INR 12000/MWh
Aug-21	2976	168	181
September	2880	84	94
October	2976	633	835
November	2880	33	14
December	2976	24	18
Jan-22	2976	10	0
February	2688	45	53

March	2976	661	686
April	2880	1689	1734
May	2976	410	669
June	2880	581	457
July	2976	237	343

Source: CEEW analysis based on data from IEX

3.4. If the high cost/marginal generator setting the market clearing price is a concern and a cause for market intervention, would Term Ahead Market (TAM) be a better option for such transactions to take place without affecting the rest of the buyers?

Longer-term contracts and the ability to lock in future prices can lend stability to market prices. However, the duration and terms of such contracts need to be carefully considered so as to avoid both short-term volatility and long-term inefficiencies. The TAM currently allows transactions for the delivery of power up to 11 days ahead and operates on the continuous matching algorithm for all contracts other than weekly contracts and uniform price step auction for weekly contracts. Due to price discovery and market clearing algorithms, TAM contracts may be vulnerable to speculative bidding. They may also see elevated price levels if participants expect supply scarcity to continue over a couple of weeks. The high prices demonstrated this in TAM observed soon after the cap on DAM was reduced from INR 20/kWh to INR 12/kWh by CERC in April 2022. Therefore, if the intent is to provide discoms with secure options to purchase power, TAM may not serve the purpose during a general scarcity situation.

Instead of crowding instruments at the spot market stage, the strategy could be strengthening other instruments such as over-the-counter (OTC) trading or intra-/inter-regional banking etc. Further, financial and physical delivery contracts of longer duration, pending implementation, also provide buyers with an avenue to hedge their risks.

3.5. Any other suggestion on mitigating the negative impact of price cap?

Price caps are a distortionary measure but necessary to protect consumers from extremely high power prices. However, in the current situation, the measures needed to protect consumers must be outside of the market. Some of these may be:

- Targeted relief for vulnerable power consumers who are getting adversely impacted by the high prices in the short-term market,
- Higher taxes on windfall profits of power generators,
- Increasing the long-term liquidity of the market by releasing plants from inefficient long-term contracts and prioritising dispatch of thermally efficient power plants,
- Implement futures and forwards to enable discoms to hedge against such price risks,
- Enhance demand forecasting accuracy by incorporating changing climate patterns and monitoring consumer category-level demand,
- Allow open access to grow and do that in a way such that demand uncertainties for discoms reduce, and
- Enabling aggregators /discoms to pool surpluses from RE and sell them in the market.

Some of these measures may be beyond the purview of the CERC and may need a coordinated response from the state governments.

4. What should be the appropriate market structure/design to encourage flexible resources like Demand Response and ESS? Apart from Time-of-Day (ToD) tariff or dynamic tariff for varied consumer categories, what are the mechanisms that can be considered for encouraging such resources? Can we think of bringing aggregators to pool together such resources and participate in the market? If yes, what should be bidding criteria or the cost recovery mechanism for such resources given that their usage is going to be limited to a very small duration during the year?

Flexible resources such as DR and BESS can respond quickly to short-term price signals (within a short period). Hence, the ancillary service or reserve market provides the necessary incentive for such flexible resources. Moreover, the market prices for reserves are usually much higher than the prices on the day-ahead or intraday market, which may give the market participant a strong incentive that can drive the demand for flexibility in the market.

These resources can be aggregated and participate in ancillary service markets as reserves (such as SRAS and TRAS), where they can be compensated for the quick response time. While primary reserves are to be maintained mandatorily by all generators for frequency response, secondary reserves are to be maintained at a regional level, and tertiary reserves are to be maintained in a distributed manner in the states (CERC 2018). Flexible sources like DR/BESS can be aggregated and participate in Ancillary Services Market.[7] The aggregators can be the entities that provides DR programs and services, such as assisting retail consumers to participate in the energy or ancillary services markets with strategies or technology to reduce their consumption during times of grid needs for a fee. Given that the aggregator needs to have a direct communication channel with the consumers, discoms and open-access traders are best placed in the system to undertake the role of 'aggregators' for the DR and BESS. However, in the current scenario, the electrical distribution network needs to be strengthened, and proper metering/AMI needs to be in place for the implementation of DR pilots.

In evolved markets like PJM and NYISO in the USA, DR and energy efficiency are already treated as resources and are compensated as any other conventional generators in the wholesale market. NYISO was the first to pilot the Demand-Side Ancillary Services Program (DSASP) (Almeter and Sellers 2015). They offer two price components - Capacity charges and Energy charges- and incentivise the fast-response systems separately.

Moreover, suppose flexible resources, such as DR and BESS, are treated as Fast-Response Ancillary Services (FRAS). In that case, they could be profitable if they bid with two components- capacity charges to keep the capacity available and energy charges to cover the operational cost. The compensation may be determined using the 'uniform clearing price' methodology, with the cheapest capacity bids selected first. The energy prices can also be considered with a lower weight to avoid gambling, as bids with extraordinary energy prices get refused no matter how low the capacity component is. The capacity that successfully participates in the AS market may not be allowed to

[7] Currently in the Ancillary Service Markets, the price discovery for Tertiary Reserve Ancillary Services (TRAS) is based on the principle of Uniform Market Clearing Price, subject to market splitting in case of congestion. While for Secondary Reserve Ancillary Services (SRAS) providers are paid from the Deviation and Ancillary Service Pool Account, for the average of SRAS-Up and SRAS-Down MW (data calculated for every 15 minutes time block in MWh) for every SRAS Provider by the Nodal Agency using the archived SCADA data at the rate of their energy charge or compensation charge (as the case may be), as declared by the SRAS Provider. SRAS Provider are also eligible for incentive based on performance as per Regulation 12 of the CERC (Ancillary Services) Regulations, 2022 which provides upto 50 paise/kWh for 95% and above response to the secondary control signal.

participate in the bulk energy market. Aggregators will be required to pool the flexible resources (DR and BESS) to respond effectively to market signals and make the flexible resources more formalised and efficient. The market prices for reserves are usually much higher than those on the day-ahead or intraday market, which may give the market participant a strong incentive that can drive the demand for flexibility in the market.

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