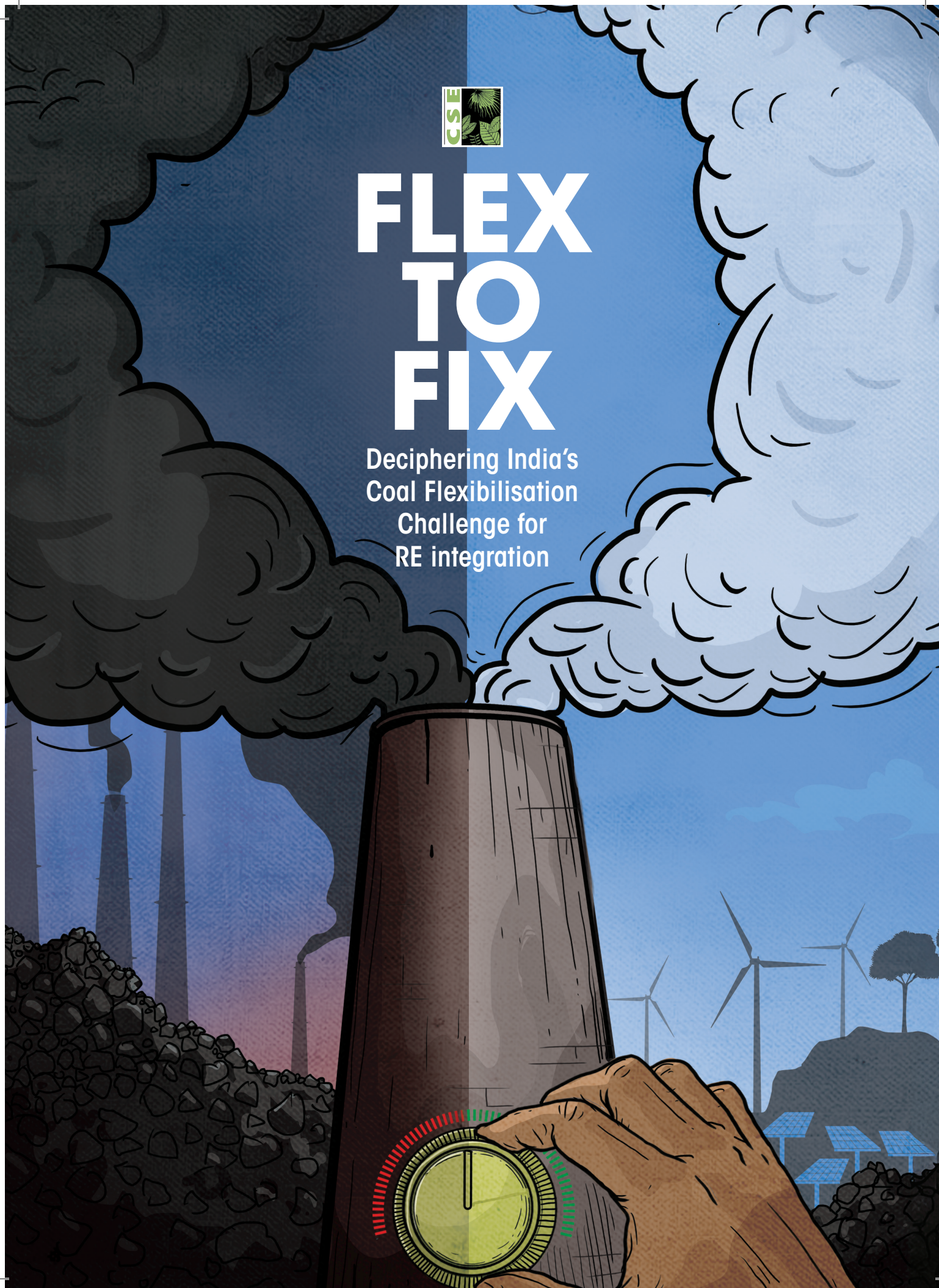




FLEX TO FIX

Deciphering India's
Coal Flexibilisation
Challenge for
RE integration





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Maps in this report are indicative and not to scale.

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EXECUTIVE SUMMARY

India's energy transition has reached a pivotal juncture. By November 2025, the nation achieved a significant milestone by reaching 50 per cent non-fossil-based installed power capacity, five years ahead of its original 2030 target. The rapid growth in RE, particularly solar energy, which has seen a 3.5-fold increase in six years, now exceeding **140 GW** of installed capacity, has fundamentally altered the demand–supply balance in the grid, creating deep intra-day variability and operational stress on conventional generation while presenting a fundamental challenge to the stability of the national power grid.

Our power system is in need of a redesign. The rise in RE reflects its evolving and dynamic nature, showcasing a need for evolution. The variable nature of power necessitates a shift away from inflexible power supply, as addition of inflexible resources will add a greater system cost. The power system can add flexibility with a variety of solutions, such as flexible coal, pumped storage, and battery storage. However, in the immediate future, coal retains the largest share of the power generation mix in India by continuing to supply over two-thirds of total electricity generation. This highlights the need to transform the major source of our power system into a flexible resource.

The need for this transition is further exposed by a structural mismatch in India's power supply. While renewable energy is variable and concentrated during daytime hours, India's electricity demand shows a second peak in the evening. The resulting “duck curve” has deepened significantly, forcing coal-based thermal power plants to ramp down during solar hours and ramp up sharply during evening peaks. Yet, India's coal fleet is designed for stable, baseload operation and is currently constrained by a minimum technical load (MTL) of ~55 per cent, limiting its ability to respond to these dynamic requirements. Hence, the first step to responding to greater renewable energy integration for the future is to flex our coal-based thermal energy supply.

7.61 TWh

of renewable energy
curtailed between
April 2025 and
March 2026

70 GW

of net load ramps
and demand
variability

≥ Rs12/kWh

of natural gas is relied
upon to meet demand
surge

Scale of the Problem

The consequences of this inflexibility are already visible:

- 7.61 TWh of RE curtailed (generation and transmission) in FY 2025-26,
- Increasing reliance on high-cost gas generation (~Rs 12/kWh) to meet demand surge,
- Rising net load ramps and demand variability exceeding 70 GW,
- Persistent high-frequency grid events due to over-injection, indicating system imbalance.

These trends represent both an economic loss (unused low-cost renewable energy) and a system risk (grid instability and inefficient dispatch). With an additional 100+ GW of solar capacity under construction, these challenges are expected to intensify unless system flexibility is urgently addressed.

Scale of the National Initiative

To address these challenges, the Central Electricity Authority (CEA) has mandated a phased implementation plan to cover 493 thermal units (196.7 GW) by 2030. The core objective is to reduce the MTL of these units from the current 55 per cent to 40 per cent, while enhancing ramp rates to at least 3 per cent per minute.

- **Technical feasibility:** Pilot studies have confirmed that most Indian coal units can technically operate at 40 per cent MTL, with some units even reaching 34 per cent.
- **International benchmarking:** The report draws on the experiences of **China**, which has already retrofitted over 300 GW of its fleet, and **Germany**, which uses a mature market-driven approach for 15-minute dispatch blocks to manage flexibility.

Implementation Reality: Significant Gap

Despite strong policy intent, implementation remains significantly behind schedule:

- Only ~1 unit (500 MW) has fully demonstrated both low-load and ramping compliance,
- Only ~1.9 GW has achieved 40 per cent MTL capability,
- Even the pilot phase (originally 5.85 GW) remains incomplete, with only 800 MW effectively achieved.

This indicates that India is still effectively in a pilot-stage reality, despite entering Phase 1 of the national rollout. The gap is not due to technical infeasibility, as pilot studies have already demonstrated feasibility, but rather due to institutional, regulatory, and financial bottlenecks that continue to limit progress.

~1 unit

of 500 MW has demonstrated low load and ramping compliance

1.9 GW

of capacity has achieved 40 per cent MTL capability

91 units

under Phase 1 of CEA's phasing plan are behind schedule

Cost and Economic Trade-Offs

Flexibilisation is not cost-neutral, yet it is the most cost-effective near-term solution for RE integration. It involves:

- CAPEX: Rs 6–30 crore per unit depending on vintage
- OPEX impacts: higher coal consumption, auxiliary usage, and life consumption
- Estimated tariff increase of ~8–15 per cent on a daily basis for flexible operation

However, when compared with alternatives:

- Short-duration BESS: ~Rs 0.8–1.0 per unit
- LDES (projected): ~Rs 3.0–4.5 per unit
- LDES (current): up to ~Rs 7.1 per unit

Flexibilisation remains the least-cost near-term solution, particularly given the scale required. Large-scale storage deployment, while essential in the long term, would require Rs 1.08–1.39 lakh crore (short-duration) and up to Rs 9.6 lakh crore (long-duration), significantly higher than retrofit-based flexibility.

System-Level Scenario Assessment

CSE analysis showcases net benefit for flexibilisation across the sector with greater RE integration, net CO₂ emission reductions alongside systemic portrayal on need of flexibility in the long run.

- ~125.1 TWh of additional annual RE integration space
- ~ 18,148 MW of additional RE absorption space during high solar hours
- ~ 92–101 million tonnes of CO₂ annually OR ~ 7.7–8.4 per cent net emissions reduction in the power sector

Key Structural Challenges

The report identifies five critical barriers:

1. **Implementation delays** in the phasing plan
2. **Regulatory asymmetry** between central and state frameworks
3. **Incomplete cost recovery mechanisms**, especially for OPEX and hidden costs

4. **PPA and contractual rigidities**, misaligned with flexible operation
5. **Environmental externalities**, managing efficiency and emissions

Additionally, inclusion of **old and inefficient units** in retrofit plans raises concerns on cost-effectiveness and long-term system efficiency.

Way Forward: Strategic Recommendations

To enable a scalable and cost-effective transition, the report proposes:

1. **Factors for reconsideration and prioritization in the Phasing plan:**
 - Heat-rate and Emission performance,
 - Consideration of greater utilisation of efficient and low-emission assets,
 - Consideration of two-shift operation for old and inefficient plants,
 - Technological limits of thermal units.
2. **Restructure compensation:** Broaden CAPEX/OPEX definitions to include mandatory training, workforce upskilling, and the costs incurred during trial or testing periods.
3. **Incentivise compliance:** Move beyond penalties. Establish incentives like preference in Merit Order Dispatch or lump-sum payouts for units that achieve flexibility targets.
4. **Mandate transparency:** Standardise the disclosure of RE curtailment costs to make the economic and environmental impact visible to planners and the public.
5. **Baseline unit health:** Conduct structured health assessments of units before retrofitting to distinguish between legacy wear-and-tear and flexibility-induced damage.
6. **Fuel and emission standards:** Mandate fuel quality assurance to reduce unit tripping during ramping and establish SOPs to manage the higher local air pollution caused by inefficient part-load operations.
7. **System flexibility based on cost competitiveness:** Strategise power system flexibility based on cost competitiveness by subjecting BESS at thermal plants to cost-reflective market dispatch, allowing transparent comparison with lower-cost flexibility alternatives.

~125.1 TWh

of additional annual
RE space created
by implementing
flexibilisation

~18 GW

of RE absorption
space created
during solar hours

~92/101 MT

of net CO₂ savings
by implementing
flexibilisation

- 8. Integrate time-of-day (TOD) pricing:** Operationalise time-of-day pricing with market-linked dispatch to enable thermal plants to competitively supply un-requisitioned power based on real-time price signals, thereby incentivising flexibility and improving system efficiency.

Conclusion

India's energy transition has entered a phase where flexibility, not capacity, is the binding constraint. While renewable energy expansion has outpaced expectations, the supporting ecosystem, particularly thermal flexibility, has not kept pace as the current report's assessment shows.

Flexibilisation of coal-based thermal power plants represents the bridge between today's coal-dependent system and a future renewable-dominant grid. It is a practical, scalable, and cost-effective solution in the near to medium term. However, without urgent course correction in implementation, regulatory alignment, and economic incentives, India risks rising curtailment, higher system costs, and grid instability, undermining the very gains of its renewable energy transition.

The next phase of India's power sector reform must therefore move decisively from policy design to execution, ensuring that flexibility becomes an embedded feature of the system, not a delayed afterthought.

1

INTRODUCTION

India has achieved 50 per cent non-fossil installed capacity, raising the need for system flexibility to integrate RE into power generation mix

Solar capacity has increased by 3.5 times to over 140 GW in the past decade, fundamentally altering grid dynamics

Coal power continues to supply over two-thirds of electricity, making it central to flexibility solutions

The mismatch between daytime solar generation and evening peak demand creates structural grid stress, necessitating a flexible power

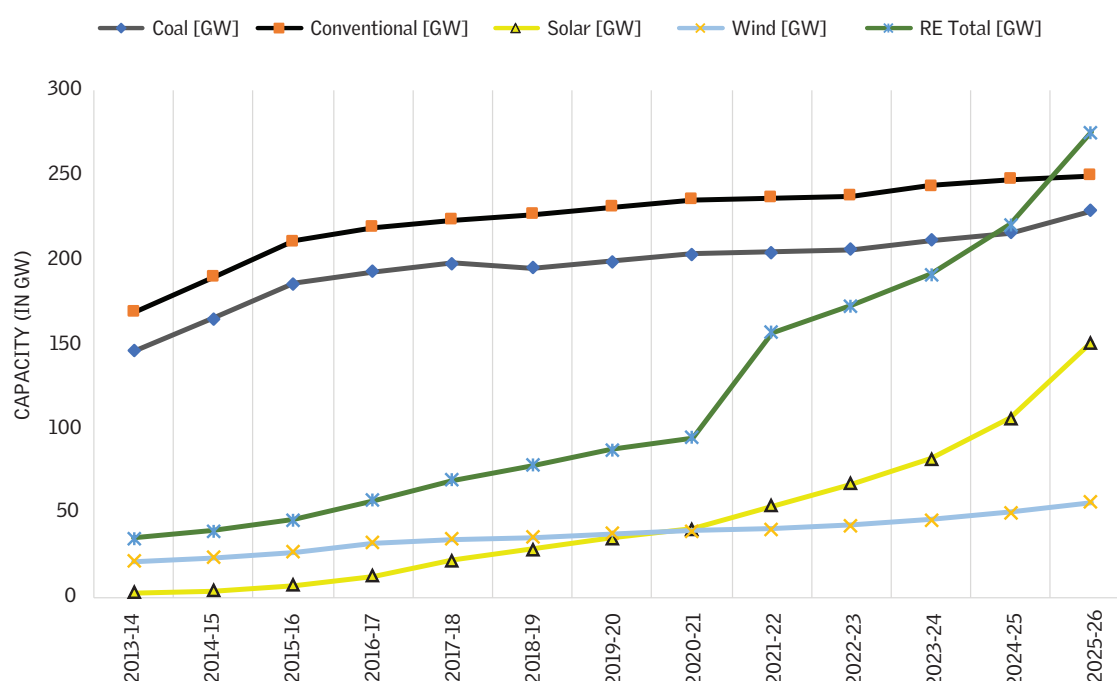




India's energy transition has been progressively advancing, with the medium-term goal of adding 500 GW of renewable energy (hereinafter RE) capacity by 2030. By November 2025, India achieved a significant milestone in its energy transition by reaching 50 per cent non-fossil-based installed power capacity. Five years ahead of its targeted timeline, India has met one of its Nationally Determined Contributions (NDCs) under the 2015 Paris Agreement. The growth of RE in India's power grid can be gauged from Graph 1, which represents a consistent rise in RE installed capacity, with solar energy's capacity recording a 3.5-fold increase over the past six years, rising from 40 GW in 2020–21 to 140.6 GW in 2025–26 (see *Graph 1: Evolution of India's Power Installed Capacity Mix (2013–14 to 2025–26)*). While the growing share of RE in the nation's installed capacity advances India's climate goals, it also brings a new set of challenges.

Even as one acknowledges the sharp growth of RE, especially solar energy, in the grid over the past few years, the question now is: *do we have the system in place to integrate the RE we will generate in the country?* The consistent share of coal under an inflexible power operational form and the increasing instances of RE curtailment may suggest otherwise. The other pertinent question is: *how much further can the share of RE grow in the current state of India's power system?*

Graph 1: Evolution of India's Power Installed Capacity Mix (2013–14 to 2025–26)



Source: CEA's monthly installed capacity report

Historically, India's power grid, like others worldwide, has been built around conventional power generation sources (i.e., fossil fuels). The key difference between conventional power sources—such as coal-, gas-, and crude oil-based thermal power plants—and RE based on solar and wind is the challenge of intermittency. RE holds a 'must-run' status under India's power ecosystem. To integrate these intermittent sources beyond a certain point into a conventional power system, India needs to transition its system into a flexible one that can leverage a variety of flexible power sources while keeping costs low for its users. To make RE a dominant source of energy in India's future energy mix, there is an impending need to reimagine the roles of both existing and emerging players in India's power ecosystem. This includes building storage at scale (which will take time) alongside reshaping conventional power sources to provide the space for RE to grow.

1.1 Rising Solar Energy and the Changing Role of Coal-Based Power

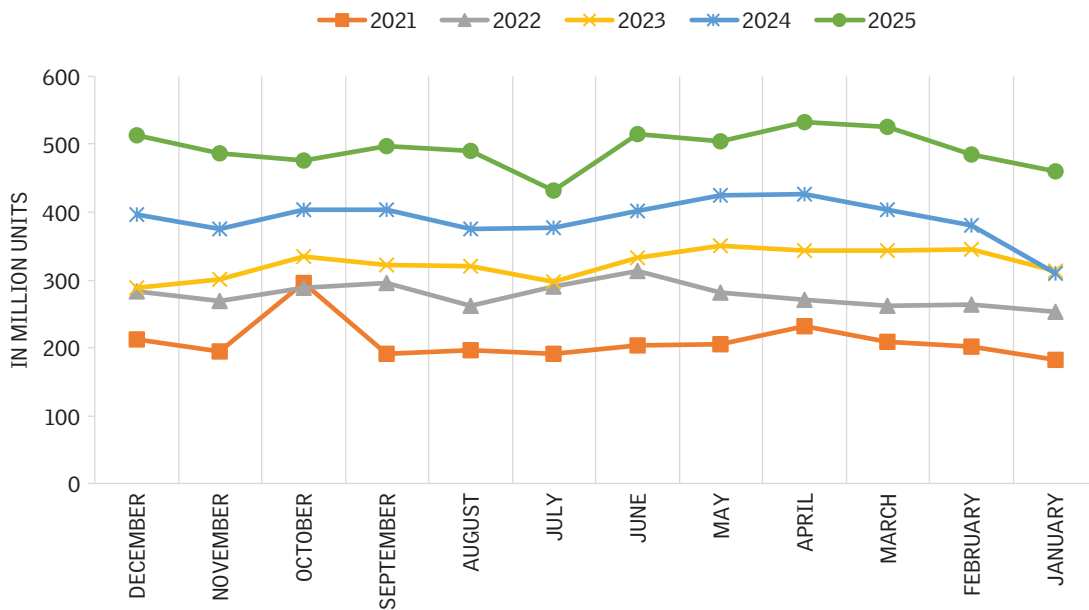
With growing penetration of renewable energy into India's power grid, the traditional role of the country's largest power source, i.e., coal-based thermal power, is evolving. Conventional power plants are designed to run at a consistently high Plant Load Factor (hereinafter, PLF), providing a stable base load. In contrast, solar energy, the dominant source of RE in India, is intermittent and available during daylight hours, with generation peaking around midday, as reflected in observed generation profiles across regions and seasons.

As solar energy is rising in India, grid availability is now increasingly considered in terms of solar and non-solar hours. Graph 2 illustrates the assessment compiled on the basis of solar generation peaks in India, showcasing that, year on year, the grid receives a greater share of solar energy each month (see *Graph 2: Evolution of Monthly Peak-Day Solar Generation (2020–25)*). With 100.6 GW of solar energy and a cumulative RE of 148.3 GW under construction as of December 2025, the systemic injection of greater RE into the grid will only increase in the future. To illustrate the injection of RE on a per day basis, refer to the graph below (see *Graph 3: CEA's Illustration of Demand and Generation on a Critical Day*).

This shift necessitates a change in the operational role of coal-based thermal power, moving from being the primary source of energy for the grid to acting as a flexible resource that adjusts output to integrate RE. During solar hours, coal plants must ramp down as solar generation rises and ramp up as solar generation declines. This dynamic adjustment is the core idea of flexibilisation.

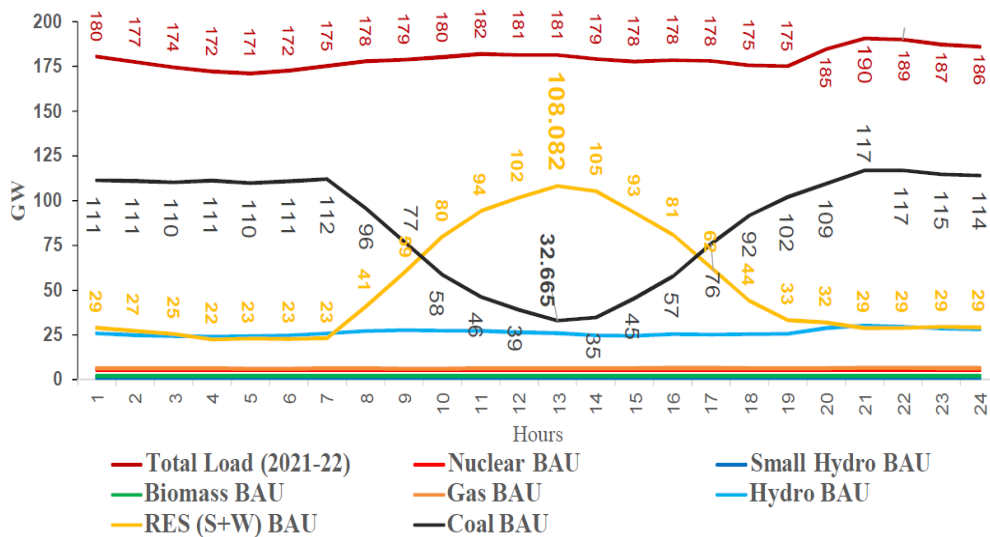
Coal-based thermal power currently operates to provide the base load for the grid, providing physical inertia and frequency stabilisation, while renewable sources

Graph 2: Evolution of Monthly Peak-Day Solar Generation (2020-25)



Source: CSE analysis of CEA's Daily Renewable Generation Report (2020-2025)

Graph 3: CEA's Illustration of Demand and Generation on a Critical Day



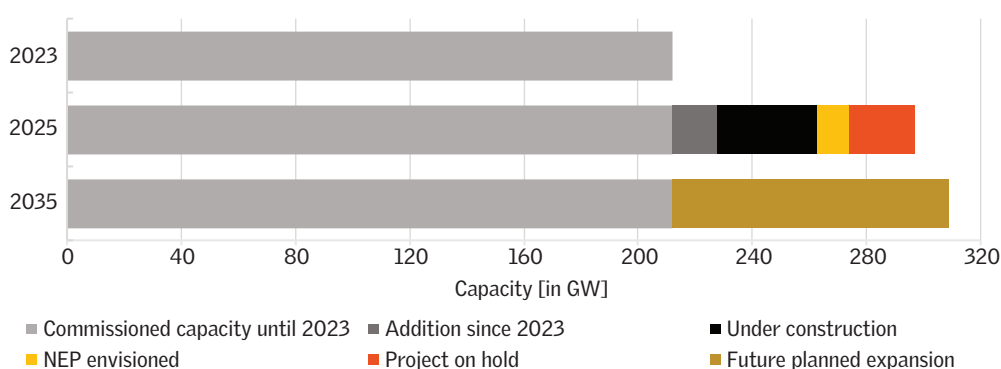
Source: CEA Report: Flexible Operation of Thermal Power Plants for Integration of Renewable Generation

typically operate in a grid-following mode. At present, around two-thirds of India's generation is provided by coal-based thermal power. Yet, during solar hours, the role of coal power is changing.

Currently, the base load is expanding and modernising simultaneously. India's installed coal capacity rose by a modest 10 GW between 2016 and 2021. In the five

years since, capacity addition has almost doubled with 16 GW added to the power grid. As per the CEA's October 2025 Broad Thermal Status Report, expected coal capacity addition to the grid in the coming year is 8.6 GW. In addition to this, a further 28.2 GW capacity is under construction. This will rise further, as the Ministry of Power is expected to add a total of 97 GW of coal capacity by 2035.

Graph 4: Coal Capacity: Current and Future Plans (in GW) (2023–35)



Source: CSE analysis on basis of multiple GoI policy documents

To enable the fleet to operate flexibly while maintaining grid stability, the Government of India notified the *Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2022* on January 25, 2023. The CEA subsequently released the phasing plan to implement the regulations across the coal-based thermal power fleet in India via Gazette of India notification on December 15, 2023.

The phased plan is necessary as the capacity of coal-based thermal power to ramp up and ramp down is technologically limited. In its current form, India's fleet can operate at a MTL of 55 per cent. Going below this threshold may endanger a unit's operational stability and introduce other risks of asset depletion. As a result, when thermal units are unable to back down below their MTL during periods of high solar generation, renewable energy is curtailed to maintain grid balance and frequency stability.

1.2 Enabling Flexible Operations of India's Coal-based Thermal Power

In this context, flexibilisation refers to the ability of thermal power plants to operate across a wider range of load levels and ramping rates, supported by appropriate operational practices, regulatory frameworks, and market mechanisms. India's

new coal-based thermal power fleet is built on newer generation technologies of supercritical and ultra supercritical power generation. These units operate at higher efficiency when running consistently with high load factors. With the CEA's announced roadmap for flexible operations as a pathway to inject greater RE into the power grid, the current and upcoming coal capacity stands at a crossroads.

Operations at lower load factors reduce efficiency and the heat rate of the unit, while increasing secondary fuel oil and auxiliary energy consumption, thereby impacting the unit's economic viability and life cycle. To address these resulting technical and economic degradations, the implementation of the CEA's roadmap is underpinned by a tariff and compensation mechanism approved by the Central Electricity Regulatory Commission (CERC). This ensures that the cost of providing flexibility is accounted for. The current CEA plan aims to target 493 units, covering 196.7 GW of coal capacity by 2030.

Against this backdrop, the report examines the status, drivers, and policy implications of the flexibilisation of coal-based thermal power plants in India. *Chapter 2* establishes the system-level and operational need for flexibilisation, highlighting challenges such as renewable energy curtailment, demand variability, the deepening duck curve, and grid stability concerns. *Chapter 3* traces the evolution of India's flexibilisation policy framework, from early technical cooperation and pilot studies to the formalisation of regulatory mandates through the CEA roadmap, regulations, and phasing plan. *Chapter 4* examines the economic and regulatory dimensions of flexibilisation, including cost structures, tariff mechanisms, and variations in compensation frameworks across central and state jurisdictions. *Chapter 5* assesses the implementation status of flexibilisation in India, evaluating progress under the phasing plan alongside plant-level operational experience. *Chapter 6* draws on the learnings from China and Germany, outlining the lessons India can draw from their policies for transitioning to flexible coal. *Chapter 7* evaluates the cost of flexibilisation and emerging alternatives, such as BESS, along with their cost and scalability implications relative to thermal flexibilisation. *Chapter 8* highlights the key findings of the policy assessment. *Chapter 9* synthesises the key technical, economic, environmental, and institutional challenges that continue to constrain progress. Finally, *Chapter 10* presents a set of targeted policy recommendations aimed at enabling a coordinated, cost-effective, and scalable transition towards flexible thermal operations in India's evolving power system.

2

NEED FOR FLEXIBILISATION IN INDIA

India curtailed approximately 7.2 TWh of renewable energy between April 2025 and January 2026, resulting in 7.8 MT of avoidable CO₂ emissions

Deepening duck curve is showcased in daily demand variability exceeding 70 GW, with steep evening ramps raising system balancing challenges

Gas-based generation, almost double the price of coal costing ~Rs 12/kWh, is increasingly used to manage peak demand due to limited coal flexibility

Despite coal plants operating at 55 per cent MTL, grid frequency exceeded 50.05 Hz, highlighting need to reduce MTL for integrating rising RE

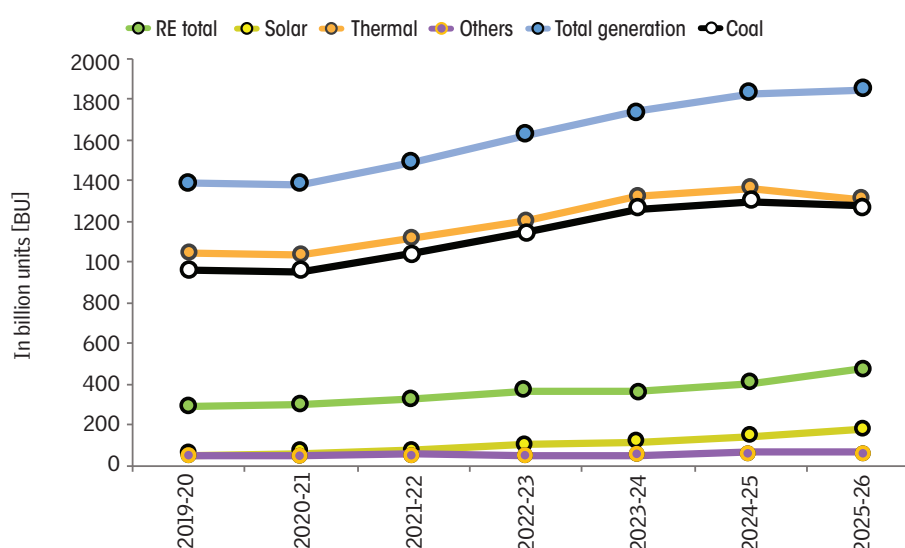


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Electricity demand in India varies significantly across regions and during the day, influenced by factors such as weather conditions, agricultural demand, economic activity, and local consumption patterns. Over the past decade, peak electricity demand has increased sharply, from about 135 GW in 2013 to over 250 GW in 2024. The surge is complimented by the rise in solar energy's share in India's power generation mix, rising from 3.6 per cent in 2019–20 to 8.9 per cent in 2025–26. The graph below illustrates the rising share of renewable, especially solar energy into India's power generation (see *Graph 5: India's Power Generation Mix Evolution (2019–2026)*).

Graph 5: India's Power Generation Mix Evolution (2019–26)



Source: CSE analysis of CEA's Monthly RE Generation Report (March 2019–January 2026)

A unique challenge of the Indian grid is that while there is growth in solar energy, it primarily feeds daytime operational needs, thus necessitating a reduction in thermal generation during the day. However, India's power generation peak usually hits around 18:00–20:00 of the day, when solar energy is unavailable. Hence, to meet this peak demand, thermal power plants (TPPs) must transition from base-load providers to flexible resources capable of ramping down during the day and up sharply for the evening peak. Thermal plants are designed to provide synchronous generation, grid-forming capabilities and inherent support for frequency and voltage stability. In contrast, RE sources are typically grid-following and intermittent. Therefore, to increase RE penetration without jeopardising the existing power system, there is a need to address three key challenges surrounding RE:

- Variability: RE varies from moment to moment
- Uncertainty: RE cannot be predicted with any certainty in advance
- Concentration: RE generation is concentrated during a limited number of hours of the year

In order to resolve these concerns, the flexible operation of existing coal-fired power plants is a key measure required in the immediate situation, especially while other alternatives—such as long-duration battery storage (hereinafter LDES)—are still maturing, with India’s current battery storage capacity limited to 0.5 GWh. Flexibilisation will ensure the security and reliability of the power supply, as well as the stability of electricity grids, while maximising generation from renewable energy sources (RES) and integrating them into the grid. Flexible operation of thermal power plants is essential for handling the instability of renewable generation between solar and non-solar hours. An illustration of the same has been provided in Illustration 1 (see *Illustration 1: CEA’s illustration of demand and generation on a critical day*). Furthermore, as the grid requires thermal power to meet the evening peak, existing daytime operations need to undergo a change with rising RE power. Additionally, India’s current grid infrastructure necessitates the need of coal-based thermal power for its operational load requirements and for the continued maintenance of its grid profile within the desired frequency conditions.

2.1 Challenges Nudging for Flexibilisation

The integration of RE into the grid is more complex than what meets the eye, as power generation units in India are not designed to continuously ramp up and down depending on the fluctuations in power demand. In this segment, we turn to some of the challenges posed by rising RE to situate the need for thermal power flexibility into our power grid.

2.1.1 RE Curtailment

In the absence of adequate flexibility, system operators resort to renewable curtailment to maintain grid stability, undermining the economic and environmental rationale of renewable deployment. The CEA’s *2019 Roadmap for Flexible Operation of Thermal Power Plants for Integration of Renewable Generation*, recognises that integrating high shares of variable renewable energy fundamentally increases flexibility requirements and that coal, hydro, and gas generation must adjust operations to maintain grid stability. In this context, the CEA concluded that a limited level of RE curtailment—around 1 per cent annually—may be allowed in the near term for grid security and stability, given the high costs of storage and other flexibility options.

To minimise curtailment, the CEA proposed a **three-step coordination framework**. First, hydro and gas generation should be reallocated to reduce daytime output and increase evening peak supply. Second, storage solutions and two-shift operations of select coal units should provide additional flexibility. Only as a third step should RE curtailment be used as a balancing measure. Even a 1 per cent curtailment level implies a substantial quantum at scale. For instance, under India’s target of **500 GW of installed renewable capacity by 2030**, a 1 per cent annual curtailment would translate to the equivalent of **5 GW of renewable capacity being unused at any given time on average**, with higher instantaneous curtailment during periods of system stress. This policy acceptance of curtailment reflects the structural limits of thermal flexibility and transmission constraints.

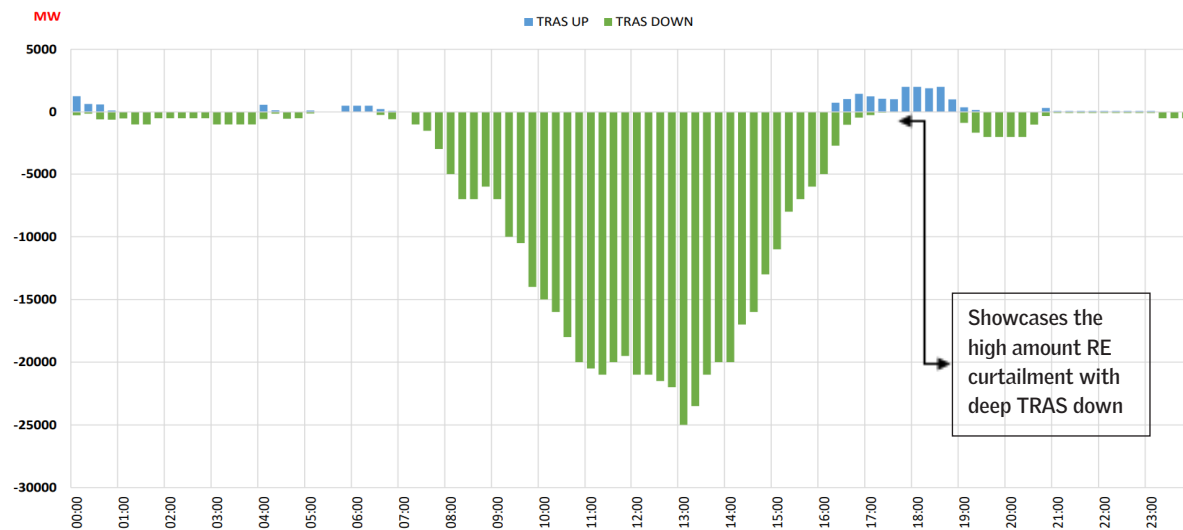
Scale of Curtailment

India does not publish consolidated national statistics on renewable energy curtailment, and neither GRID-India nor the CEA provides aggregated annual curtailment estimates in public system reports. However, the scale of curtailment can be inferred from **GRID-India’s daily Renewable Energy Management Centre (REMC)/Variable Renewable Energy (VRE) reports**, which document instances of solar and wind output reduction triggered through operational interventions—such as Tertiary Reserves Ancillary Services (TRAS)—and absolute RE curtailment for that particular day.

TRAS Up and TRAS Down are mechanisms operated by GRID-India through the National Load Despatch Centre (NLDC) to manage real-time power system imbalances. **TRAS Up** is procured to increase generation when demand exceeds the forecast or when renewable output falls, thereby arresting low-frequency conditions and preventing supply shortages. **TRAS Down** is procured to decrease generation when supply exceeds demand, particularly during periods of high solar or wind generation, to prevent high-frequency excursions and system instability.

TRAS is operated by the NLDC as the third layer of grid defence, after primary and secondary reserves, to rapidly adjust generation during real-time system imbalances. Emergency TRAS is frequently triggered in India because of forecast errors in demand and renewable generation, limited downward flexibility in thermal plants, and transmission constraints that restrict power evacuation. In such conditions, system operators curtail renewable generation to prevent frequency excursions and grid instability. For instance, ISTS-connected solar projects experienced curtailment of around **45 GWh on 25 May 2025**, rising to **93.3 GWh on 12 October 2025**, indicating significant episodic curtailment events (see *Graph 6: Tertiary Reserve Ancillary Services (TRAS): October 12, 2025*).

Graph 6: Tertiary Reserve Ancillary Services (TRAS): October 12, 2025



Source: GRID-India Daily AS report – October 12, 2025

These interventions prevent system collapse by arresting oversupply and frequency deviations, but they also reflect structural flexibility gaps in the power system.

However, the scale of curtailment is high owing to inflexibility in the power system during daytime operations. CSE undertook an independent analysis to arrive at the scale of curtailment at the system level by computing together the daily VRE reports from April 2025 until March 2026. These numbers provide an estimate of the total units of electricity curtailed during the specified time period. For the purpose of clarity in data reflection, GRID-India's curtailment data for technical/real-time scheduling adjustments and explicit backing down/non-dispatch have been represented as generation-related curtailment and transmission-related curtailment under the heads of Wind and Solar energy. In totality, this reflects the electricity that was available but not injected into the grid.

CSE's analysis of the GRID data from April 2025 until March 2026, showcases that solar energy with a cumulative total of **7136.39 GWh** was curtailed. Generation-related curtailment of 2464.7 GWh along with transmission-related curtailment of 4672.12 GWh represents systemic issues in RE integration during solar hours. Similarly, for wind energy, a cumulative total of **486.99 GWh** was curtailed. Transmission-related curtailment totalling 410.02 GWh is almost four times more than generation-related curtailment totalling 76.97 GWh, highlighting the solar hour integration challenge (see *Table 1: RE Curtailment Assessment (FY 2025–2026)*).

Table 1: RE Curtailment Assessment (FY 2025–26)

	Wind Energy Curtailment		Solar Energy Curtailment	
	Generation-Related Curtailment [in GWh]	Transmission-Related Curtailment [in GWh]	Generation-Related Curtailment [in GWh]	Transmission-Related Curtailment [in GWh]
Total	76.97	410.02	2464.27	4672.12
Mar-26	30.98	10.05	2374.5	90.81
Feb-26	1.27	1.67	17.79	11.67
Jan-26	0.3	1.3	5.6	20.0
Dec-25	0.1	0.0	0.5	0.0
Nov-25	10.5	2.2	3579	11.1
Oct-25	32.0	20.9	835.4	59.6
Sep-25	0.0	23.7	409.8	58.7
Aug-25	0.0	220.0	244.2	192.5
Jul-25	0.9	8.5	29.4	279
Jun-25	0.0	36.8	194.2	40.2
May-25	0.1	82.7	120.1	4102.7
Apr-25	0.0	1.7	0.0	53.1
Cumulative energy curtailment [in GWh]	486.99		7136.39	

Source: GRID-India Daily VRE Report (April 2025–March 2026)

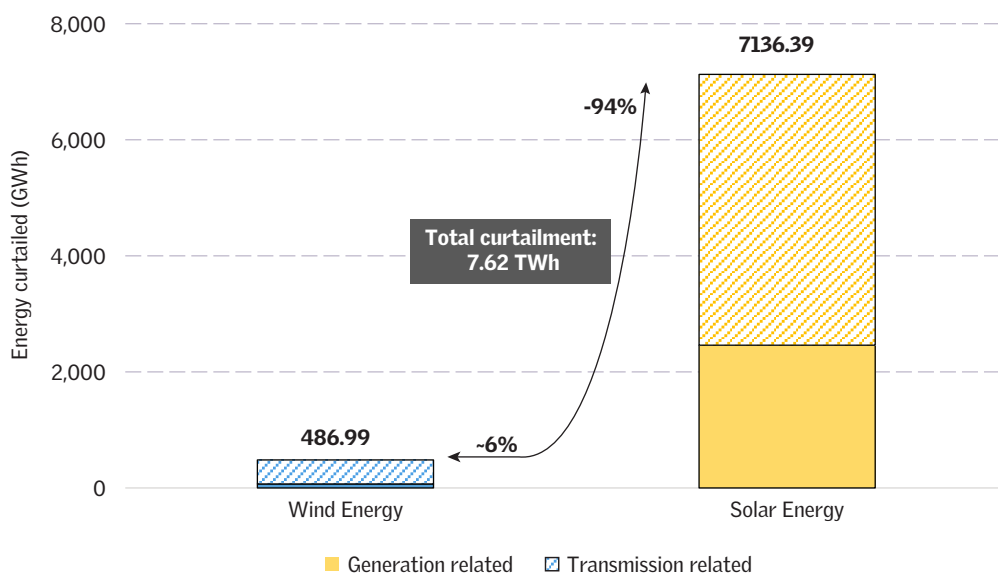
Table 2: Aggregate RE Curtailment (FY 2025–26)

	Cumulative Generation-Related Curtailment (Wind + Solar) [in GWh]	Cumulative Transmission-Related Curtailment (Wind + Solar) [in GWh]
	2541.2	5082.1
Aggregate curtailment [FY 2025–26] [in TWh]	2.54	5.08
Total energy curtailment [in TWh]	7.62	

Source: GRID-India Daily VRE Report (April 2025–March 2026)

Cumulatively, the generation-related curtailment stands at 2.54 TWh, while transmission-related curtailment stands at 5.08 TWh. The figures showcase the systemic limitation of RE integration while it is almost equal to installed fossil capacity. In totality, the energy curtailed amounts to **7.62 TWh**.

Graph 7: Renewable Energy Curtailment in India (FY 2025–26)



Source: CSE analysis of GRID-India VRE reports

The curtailment figures spanning the 12-month period amount to **1.6 per cent of total RE generation**, which is **0.41 per cent of total electricity generation**. Overall, RE curtailment represents a dual economic and environmental cost. Distribution companies and consumers often pay for contracted renewable power through fixed charges or must-run obligations, yet the curtailed energy is not consumed, resulting in sunk system costs without delivered electricity. Simultaneously, replacing curtailed renewable generation with fossil-based generation undermines the decarbonisation objective of renewable deployment and imposes long-term climate and air pollution costs, thereby eroding the economic and environmental rationale for India's renewable energy transition. With 44.62 GW of installed capacity addition in solar energy between April 2025 and March 2026, alongside an additional 90 GW of standalone solar and 189.9 GW of hybrid capacity under construction, the challenge of accommodating daytime solar energy into the power grid will only increase over time.

Persistent curtailment risks also dampen the long-term investment outlook for renewable energy, as investors factor in lower realised generation and revenue uncertainty, potentially reinforcing a reliance on thermal generation in the absence of adequate capital investment in grid upgrades and flexibility resources.

2.1.2 Variability of Power Demand

Power demand is a continuous process with a consistency that varies depending on multiple variable factors, including festivals and events. India operates one national power grid, and therefore there is interconnectivity across the system, invariably meaning that the management of power functions via a continuous loop between one central authority at the top and the many states at the bottom. In India, the National Load Despatch Centre (NLDC) handles the final dispatch decisions on the basis of power demand assessment. The NLDC is supported in demand assessment by five Regional Load Despatch Centres (RLDCs), which synchronise this based on the assessments given by each State Load Despatch Centre (SLDC).

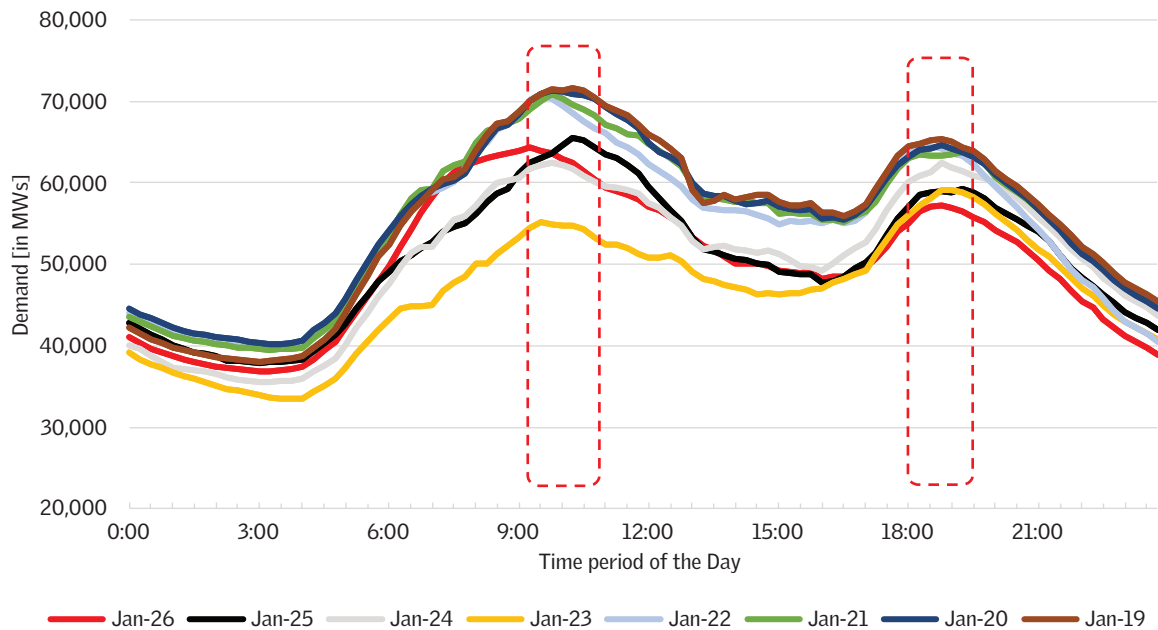
To analyse demand, a day is broken down into blocks of 15 minutes, with each day representing a total of 96 blocks. Power generators are given a day-ahead schedule for generation, i.e., a time-block-wise dispatch instruction issued by load despatch centres based on demand forecasts, generation availability, and network constraints, which serves as the primary operational plan for maintaining the supply–demand balance in the power system. For example, if the generation schedule is for 30 January, the system operator typically finalises and communicates this schedule by the night of 28 January, giving a full day in advance, or 24 hours in general. This allows generators to plan fuel, staffing, and unit operations accordingly.

In contrast to coal-based thermal power, which operates consistently throughout the day and provides a continuous, dispatchable output, renewable energy—particularly solar energy—exhibits inherent intermittency with temporal variability. Power demand variability becomes greatly pronounced in the Indian context, with India’s peak power demand arising in the early morning hours and subsequently peaking in the evening hours around 18:00–19:00. As solar generation is concentrated during midday hours, it is largely unavailable to meet these demand peaks.

The graph below illustrates the power demand variability using the recent winter demand profile (January 19–26, 2026) of India’s northern power system. Even with lower overall winter demand, the daily demand profile varies significantly, featuring two distinct daily peaks, both occurring outside peak solar generation hours—which are typically limited to the midday window between 11:00 and 15:00 (see *Graph 8: Power Demand of Northern GRID (January 19–26, 2026)*).

Yet, the actual schedule on any given day fluctuates owing to a variety of factors, with demand deviations occurring even between two states. An illustration of

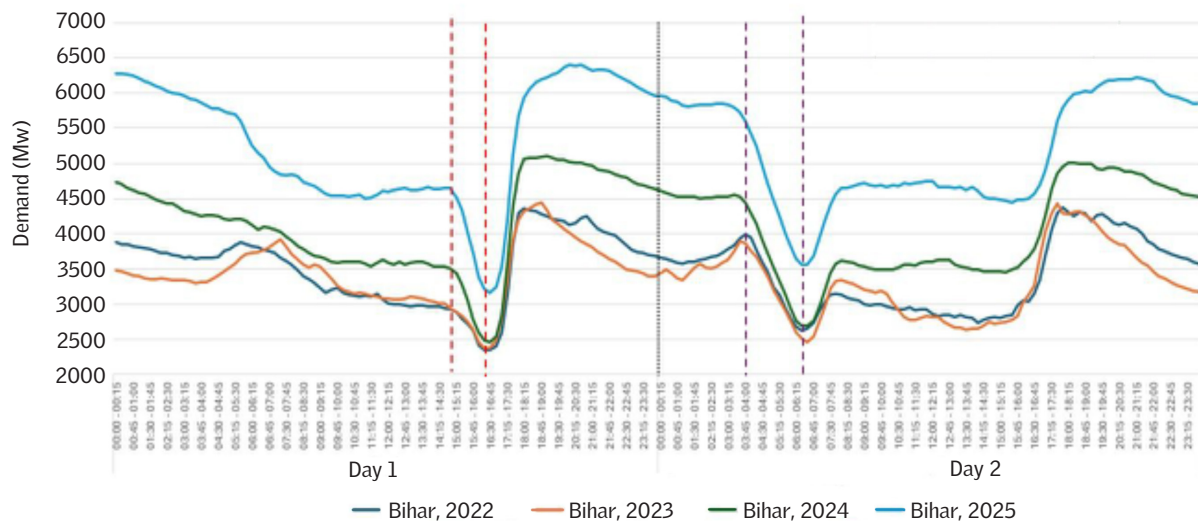
Graph 8: Power Demand of Northern GRID (January 19-26, 2026)



Source: CSE Analysis of NRLDC Intra Day Forecast Report (January 19-26, 2026)

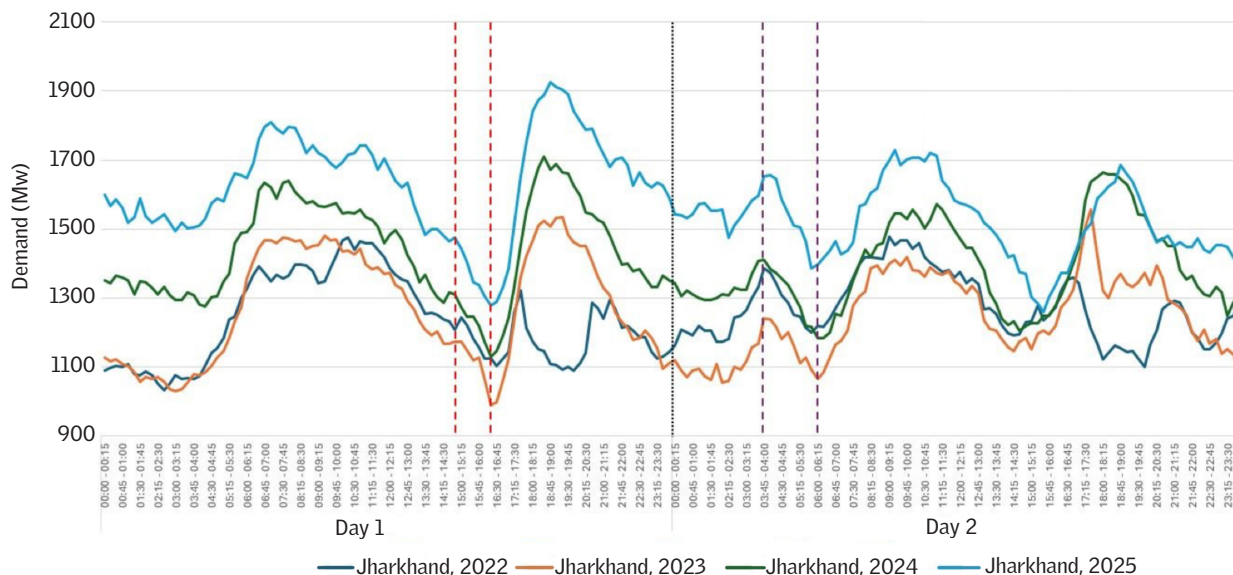
power demand fluctuation can be seen from the example of Chhath Puja, which fell on 27-28 October 2025, in the states of Bihar and Jharkhand (see *Graph 9: Chhath Demand Pattern of Bihar for the Last Four Years (2022-25)* and *Graph 10: Chhath Demand Pattern of Jharkhand for the Last Four Years (2022-25)*). The two graphs showcase that the consistent year-on-year rise in power demand

Graph 9: Chhath Demand Pattern of Bihar for the Last Four Years (2022-25)



Source: GRID-India

Graph 10: Chhath Demand Pattern of Jharkhand for the Last Four Years (2022–25)



Source: GRID-India

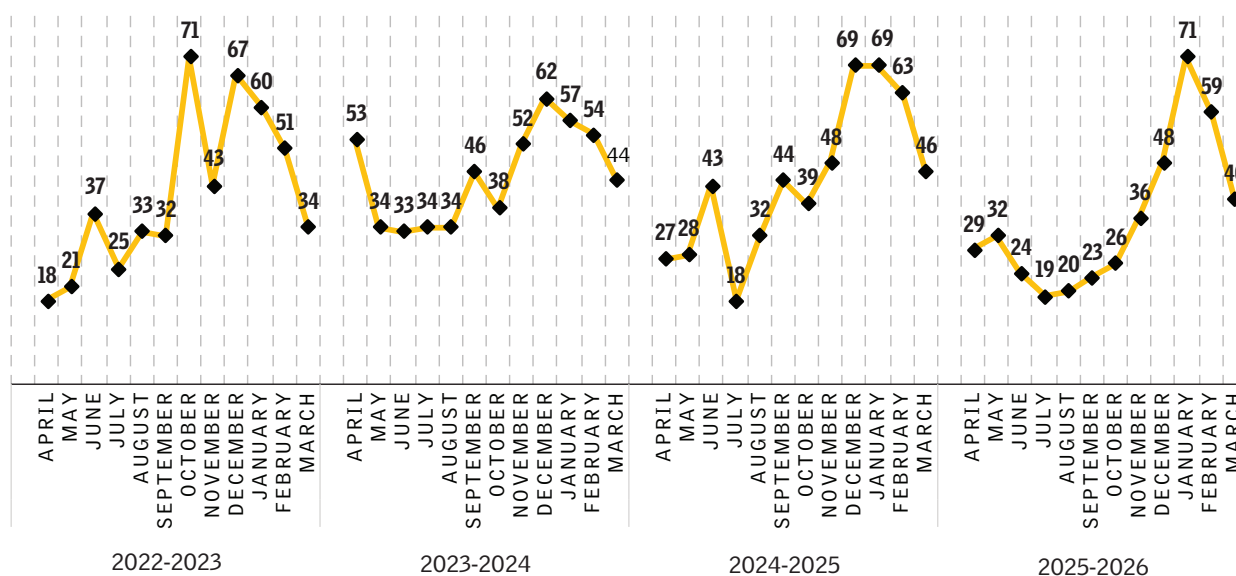
is complimented by demand variability, notably within the time slots of rising and falling demand, overlaid with solar energy hours. A key finding from this data is the variance in demand at the same time across different locations, necessitating a flexible power system that addresses supply requirements accordingly.

Fluctuation in Power Demand

The pattern of fluctuation in demand is a system-level challenge. According to the CEA's 2022–23 analysis for flexible power needs, the difference between daily maximum and minimum demand has risen steadily since 2008, reaching **over 70 GW** during 2021–22. This trajectory raises the thermal flexibility requirements to **8–9 GW** per annum. Systemic fluctuation on a monthly level presents an additional challenge necessitating flexibility in operations. CSE's analysis of the changeover between maximum and minimum demand (or peak and lean demand) for each month over the past four years illustrates the scale of power demand rise in a heterogeneous manner. Noticeably, power demand fluctuation tends to rise in the winter months—a period characterised by slowing winds and reduced solar energy.

The fluctuation in demand herein highlights the rising need for a thermal power reserve to enable the power grid to supply energy. The gap between peak and lean demand within a month highlights the shifting nature of base load energy requirement on a week-to-week basis. This reinforces the need for coal-

Graph 11: Monthly Average Fluctuation Between Peak and Lean Demand (FY 2022–26)
(in percentage)



Source: CSE analysis of GRID-India's monthly forecast figures

based thermal power to operate at lower loads with consistent requirements for flexibility in operations. The fluctuation in demand is addressed through the need for power generators to **ramp up or ramp down their output in real time** to match the changing system load. This operational adjustment is necessary because electricity systems must maintain a near-instantaneous balance between supply and demand.

Surge in Power Demand: Reliance on Gas

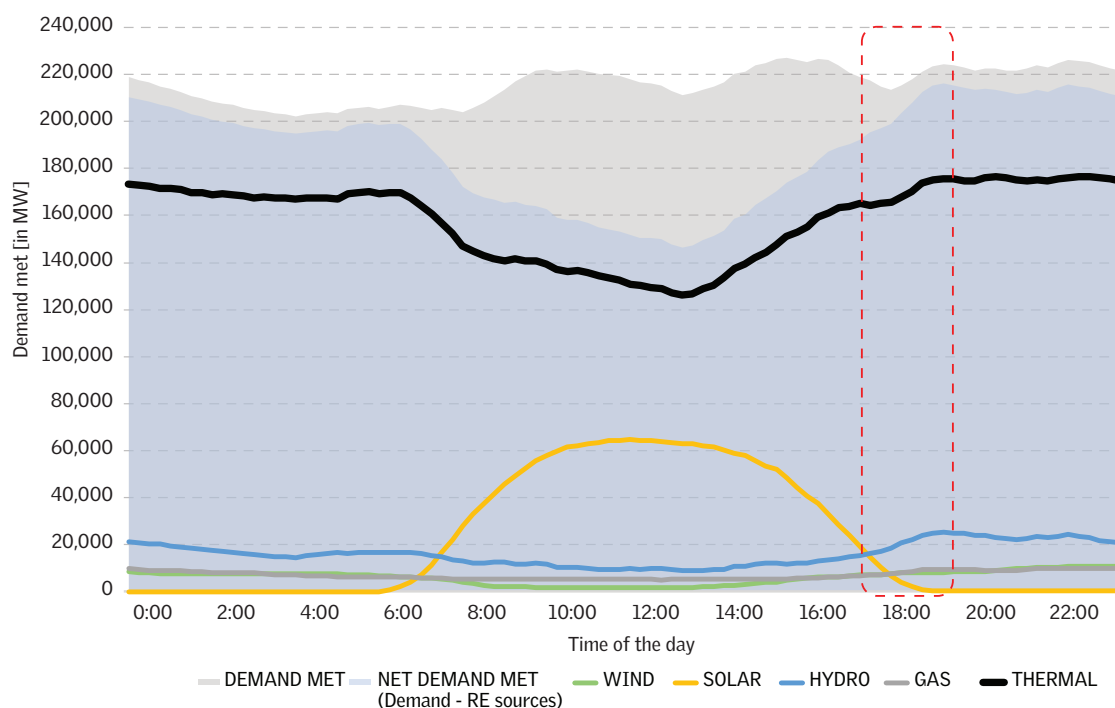
Currently, the power demand challenge is further highlighted by sudden surges. India's power system experiences two distinct daily demand surge periods. The first occurs in the **early morning (around 06:00–08:00 hours)**, when economic activity begins and residential and commercial electricity use rises. The second, and more critical, surge occurs during the **evening hours around sunset (18:00–20:00 hours)**, when lighting and household demand increase sharply while solar generation declines. This evening period typically coincides with the **daily system peak demand**, requiring a rapid ramp-up of coal-based thermal generation to compensate for the loss of solar output. Consequently, thermal plants must simultaneously increase generation while solar energy ramps down, creating steep net-load ramps and placing significant operational stress on dispatchable resources.

To illustrate the magnitude of the demand surge, the demand profile of two days of high RE penetration in 2025 is showcased in graphs 9 and 10 (see *Graph 9: Chhath Demand Pattern of Bihar for the Last Four Years (2022–2025)* and *Graph 10: Chhath Demand Pattern of Jharkhand for the Last Four Years (2022–2025)*).

The time-series data for 23 April illustrates a pronounced evening demand surge beginning around 17:00 hours, with total demand rising from 213 GW at 18:15 to over 224 GW by 19:30 hours, coinciding with a sharp collapse in solar generation from 19,437 MW at 17:30 to only 280 MW by 19:30 hours. Coal-based thermal generation increases during this period but ramps up gradually, rising from 165 GW at 18:15 to 175 GW by 19:30, reflecting technical ramp rate constraints and the minimum operating limits of coal units. In contrast, gas-based generation responds rapidly to the steep net-load ramp, increasing from 7.7 GW at 18:15 to 9.5 GW by 19:30, rising by 6–8 per cent in each 15-minute block during this period.

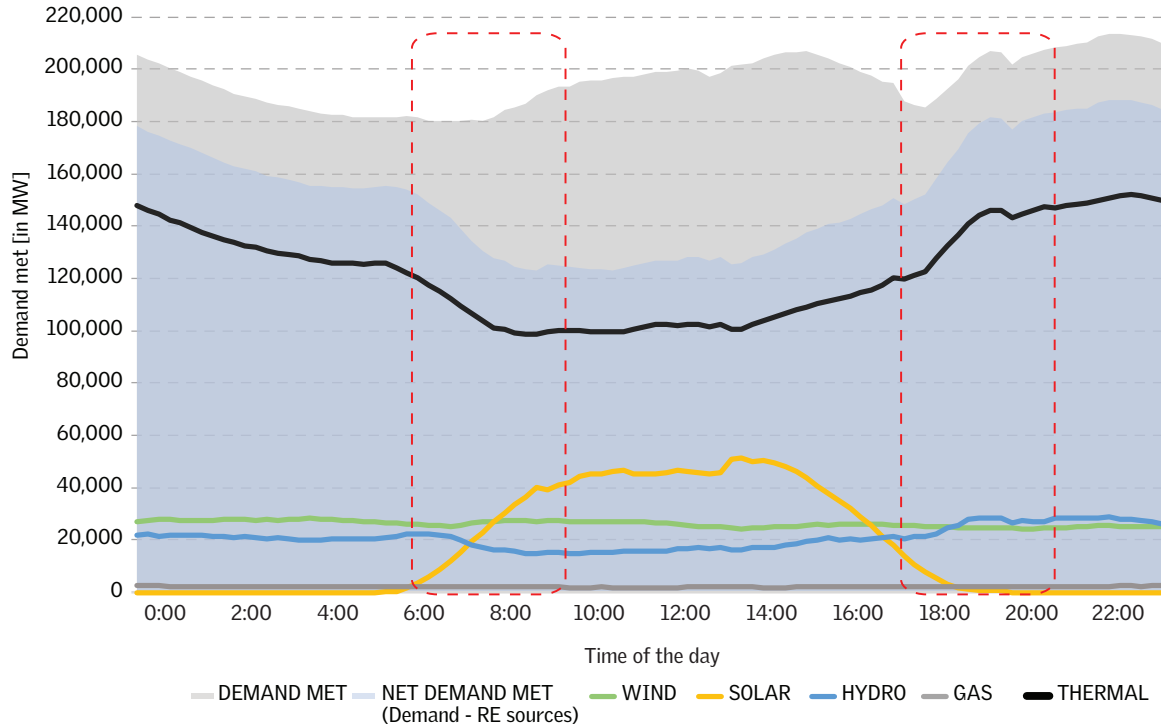
The time-series data for 31 May illustrates a pronounced evening net-load ramp beginning around 17:15–17:30 hours, with total demand rising from 185 GW at 18:15 to over 204 GW by 19:30 hours, coinciding with a sharp collapse in solar

Graph 12: All India Demand Met: April 23, 2025



Source: GRID India Daily PSP Report – April 23, 2025

Graph 13: All India Demand Met: May 31, 2025

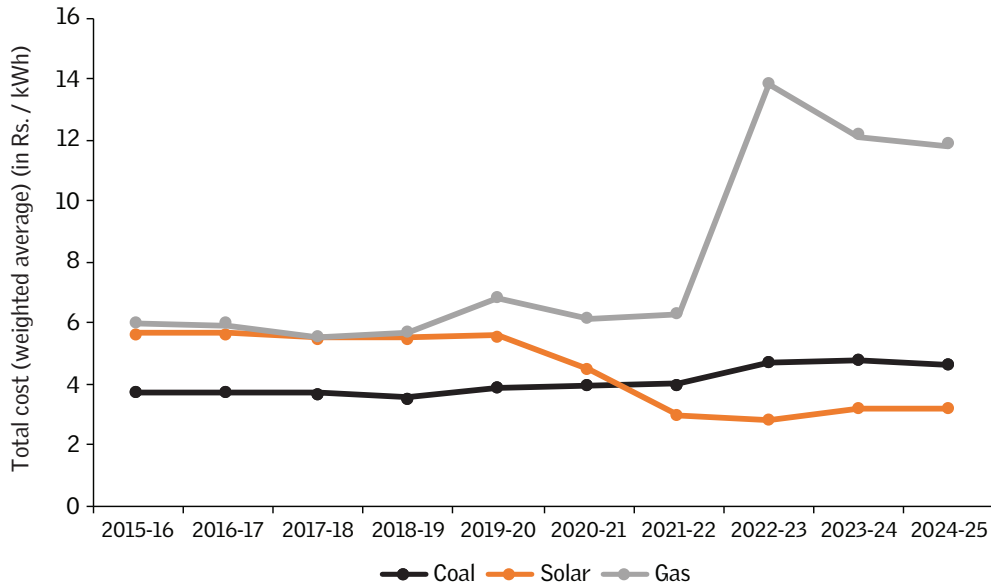


Source: GRID India Daily PSP Report – May 31, 2025

generation from 18,148 MW at 17:30 to only 601 MW by 19:30 hours. Coal-based thermal generation increases during this period but ramps up gradually, rising from 120 GW at 17:30 to 144 GW by 19:30, reflecting technical ramp rate constraints and the minimum operating limits of coal units.

In totality, with sunset, power demand rises towards its evening peak while solar production dissipates, requiring rapid production surge in thermal generation. Currently, owing to the ramping constraints of coal-based power, gas production fills this gap. Looking at the block-wise data for gas production, it shows that gas generation exhibits sharp and rapid fluctuations, increasing by 10–12 per cent within a single 15-minute block during peak periods, followed by sudden declines of 8–14 per cent in subsequent blocks. For instance, gas output rose by 10 per cent in one block and then fell by 10–11 per cent in the next, indicating rapid dispatch adjustments by the system operator. Such high-frequency ramping and reversal behaviour underscores the role of gas plants as fast-response balancing resources, deployed to manage short-term demand surges and renewable variability when coal units cannot adjust output at comparable speeds.

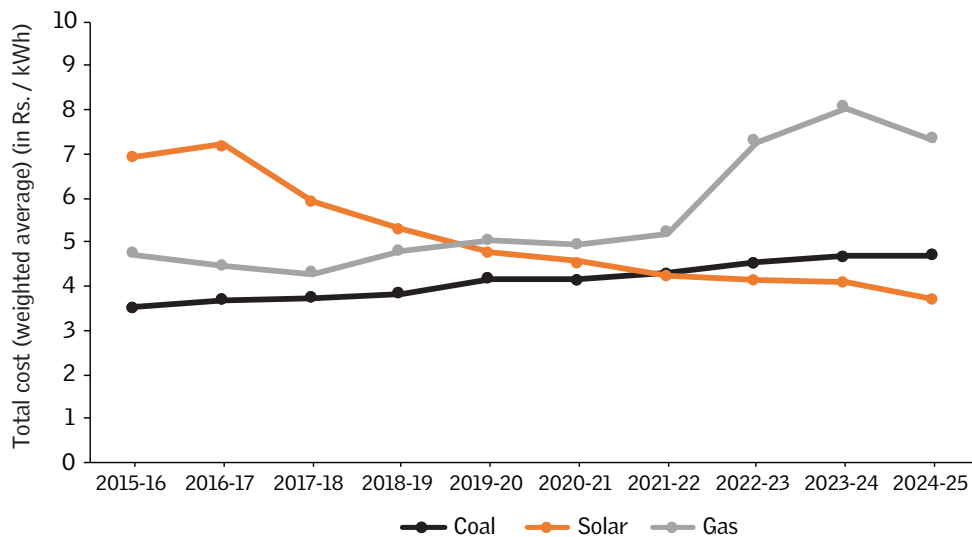
Graph 14: Total Cost of Energy Fuels in Delhi: Coal, Solar, and Natural Gas



Source: India Climate & Energy Dashboard

The economic cost of gas usage for power generation has a negative impact on the energy costs owing to the high cost of gas, with current price totalling to Rs 12.57/kWh. The final cost of gas becomes more pronounced owing to the high transit cost of the fuel and the limited infrastructure around its usage across India. For instance, the final DISCOM price for gas in the state of Delhi amounts to Rs 12/

Graph 15: Total Cost (Weighted Average): Gas vs Other Energy Sources



Source: India Climate & Energy Dashboard

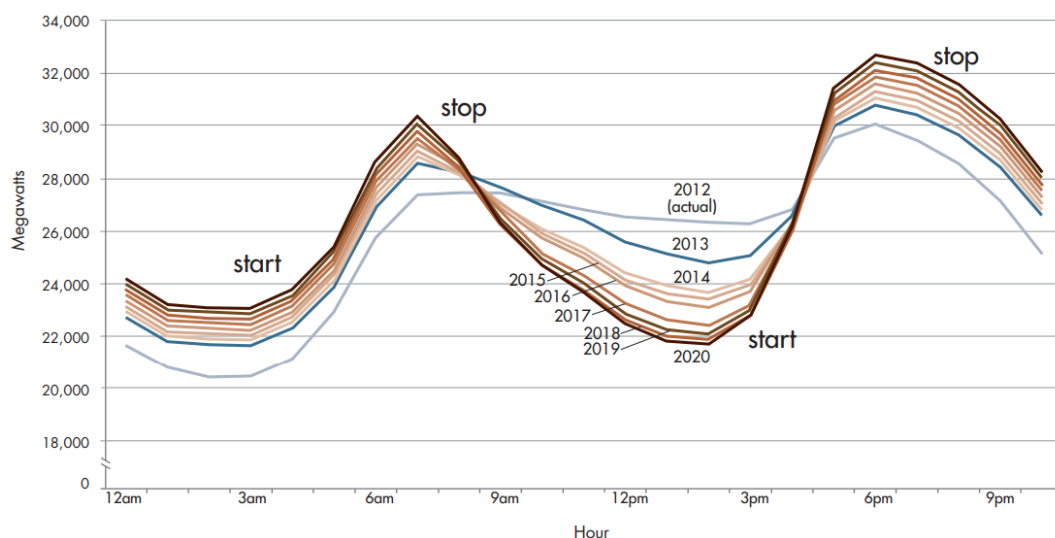
kWh—more than double the price of the next fuel and triple the price of coal in the state. India's reliance on imports for gas have always reflected in the energy source being a greater economic burden than coal power. The systemic constraints in ramping have a negative economic and environmental impact.

The utilisation of gas-based thermal units to meet surges highlights a lack of system flexibility. The demand profile analysis also showcases the rise in solar generation and the subsequent dip it causes during solar hours. This phenomenon is increasingly active in the Indian power system, and its role in requiring flexibilisation is explored in the next segment.

2.1.3 Deepening of the Duck Curve

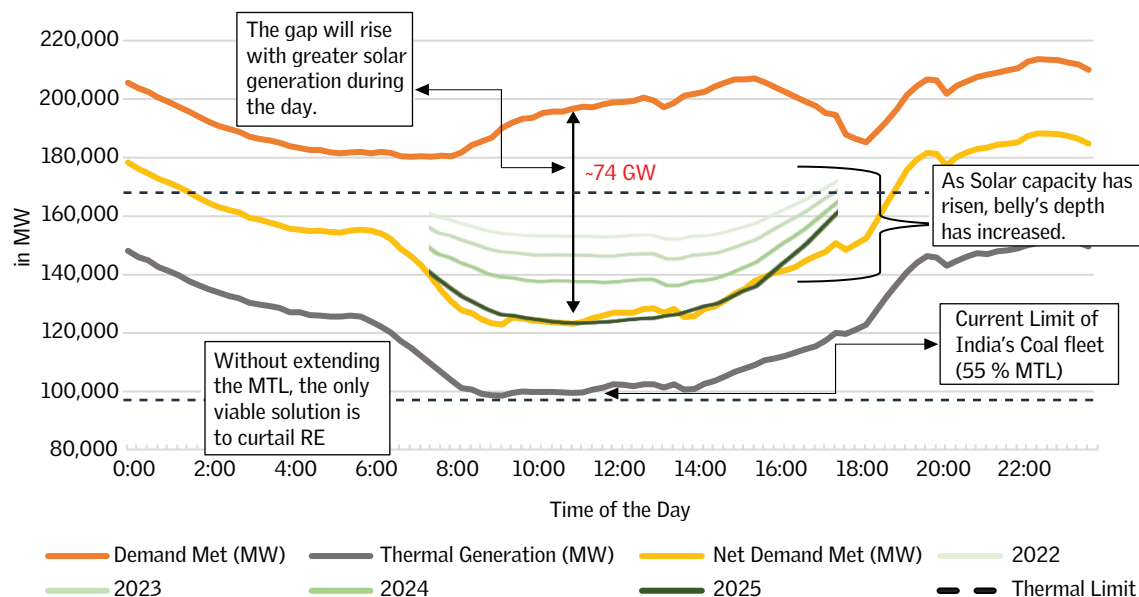
The “duck curve” describes the net load profile that emerges when high solar generation depresses midday demand for conventional power, followed by a steep ramp in the evening as solar output declines and demand rises. Net load is calculated by subtracting variable renewable generation, primarily solar and wind, from total electricity demand at each time interval, indicating the residual demand that must be met by conventional sources such as coal, gas, and hydro. As solar output rises during midday, net load falls sharply, and as solar generation drops in the evening, net load increases rapidly, creating the characteristic duck-shaped curve. A deepening duck curve intensifies operational challenges, requiring thermal plants to ramp down to low loads and ramp up sharply within hours, underscoring the need for enhanced thermal flexibility to maintain system reliability.

Graph 16: Indicative Duck Curve: California Net Load



Source: California Independent System Operator: Fast facts on duck curve

Graph 17: India's Duck Curve: Thermal Fleet Stress Under Rising Solar Penetration



With India's solar penetration rising, the phenomenon of duck curve is slowing becoming visible in India's power grid. CSE extrapolated the maximum solar generation days from 2022–2025 onto a time-series sheet for May 31, 2025 to showcase the deepening of India's duck curve.

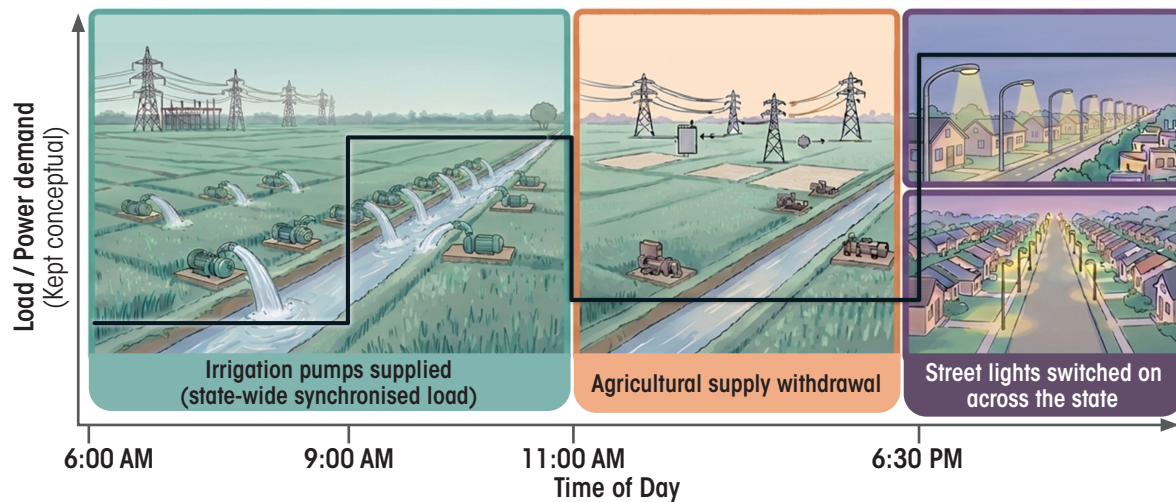
Graph 17 showcases the progressive deepening of the duck curve belly over the past four years. May 31, 2025 was a high solar energy generation day, with solar energy contributing 34 per cent of the net power demand during solar hours, providing a total supply of 43 GW. The result of this high solar generation is translated into thermal generation touching its MTL of 55 per cent during the day. The dotted line showcases the limit of thermal units to ramp down on that particular day. Notably, these units were already at their MTL during the afternoon.

Solar generation has progressively increased in line with rise in increased capacity of solar energy. Subsequent rise will require thermal units to extend their MTL or risk further RE curtailment. The need for flexibility becomes clear by the evening hours, as the peak demand for the day arrives around the sunset, necessitating that thermal units ramp up production rapidly.

The graph reflects the limit of the system; any further suppression of power demand or greater injection of RE will result in the curtailment of RE to ensure continued thermal unit operations. In 2025, India's power demand fell in

Graph 18: Synchronised Demand Jumps in India's Power System

Similar type of electrical loads come online simultaneously across India, causing sudden jumps in power demand



Source: CSE analysis + Google Nano Banana usage

comparison to the preceding years. Lower power demand, coupled with rising solar energy capacity and continuous inflexibility of thermal power units resulted in greater RE curtailment. This problem will become more acute without an increase in thermal flexibility.

Furthermore, Indian power demand has systemic rigidities that become more pronounced in the face of the country's power consumption patterns. India's power demand rises in blocks owing to large-scale state-provided power in rural areas. The water pumps are scheduled to run at a specific hour of the day and shut down at the designated hour, resulting in power rise in form of bulk-blocks rather than a consistent rise over an extended period (see *Graph 18: Synchronised demand jumps in India's power system*).

The result is a greater power reserve requirement for ramping in the power grid during these jumps. The bulk consumption pattern is a challenge that necessitates flexibility in generation, with ramp-up and ramp-down capability. The ability to ramp down becomes more complicated by the systemic rigidities unable to absorb excess power in case of demand stress. The impact of this phenomenon is reflected in the GRID's frequency profile coming under pressure. This challenge is examined in the next segment.

2.1.4 Frequency Profile Maintenance

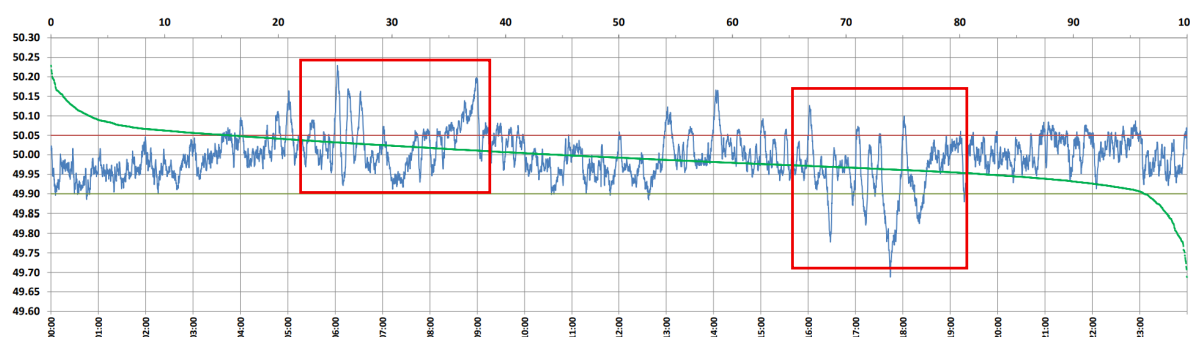
In India, the NLDC is responsible for maintaining system frequency within a narrow operational band of **49.9–50.05 Hz**, as prescribed under the *Indian Electricity Grid Code (IEGC)*. When demand rises suddenly and generation does not increase, frequency drops and conversely, when generation exceeds demand, frequency rises. Both conditions require corrective action through generation ramping, reserves activation, or load control.

As demand variability increases due to consumer behaviour, renewable generation, and regional heterogeneity, the need for thermal generators to ramp their output more frequently and rapidly has become a core operational challenge for the power system.

Under Regulation 6.5.11 of the IEGC, renewable energy generation has a ‘must-run’ status. Rules governing Merit Order Dispatch are not applicable to generation units under the ‘must-run’ category. This establishes the need for coal-based thermal power plants to reduce energy generation during daytime hours when a greater amount of RE, especially solar, is being generated. GRID-India’s daily frequency profile reports illustrate this situation in real time showcasing the need of the GRID at different hours of the day (see *Graph 19: Indian GRID – Frequency Profile: December 17, 2025*).

Variable renewable energy generation, combined with persistent and inflexible coal-based thermal generation, came to head in long-duration frequency mismatch events risking the power grid.

Graph 19: Indian GRID – Frequency Profile: December 17, 2025



Source: GRID-India – Daily frequency profile report

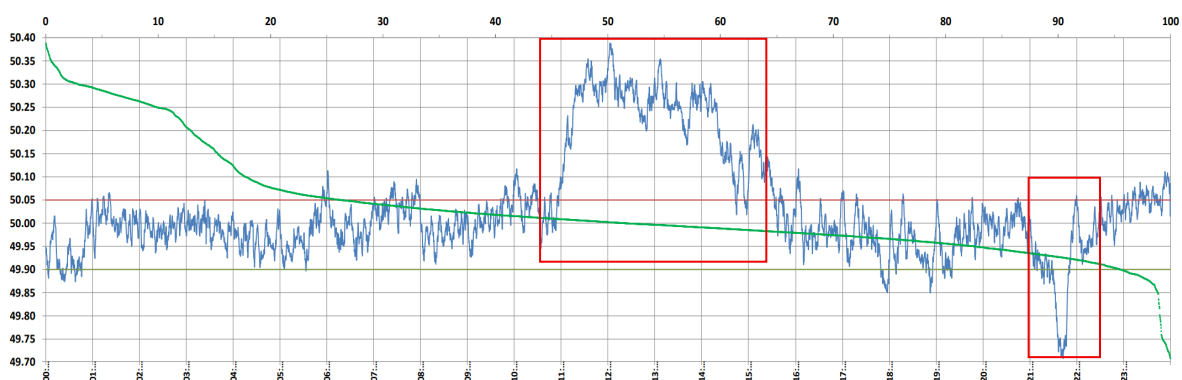
2.1.5 Risk of Over-Injection

Sustained high-frequency conditions can damage equipment, trigger protection systems, and in extreme cases, cause generator tripping or grid instability. In August 2024, the Indian grid experienced persistent high-frequency operations on multiple days, prompting a suo motu regulatory intervention by the CERC. These events revealed the systemic inability of generation, demand scheduling, and market mechanisms to adjust dynamically to real-time system conditions, thereby highlighting the emerging need for power system flexibilisation as a core policy objective.

The case examined the high-frequency events of 4, 11, and 25 August 2024, and the subsequent regulatory and operational responses mandated by the CERC. The episodes were characterised by sustained frequency excursions beyond the permissible band due to a combination of thermal minimum load constraints, renewable over-injection, suppressed demand, and inadequate downward reserves.

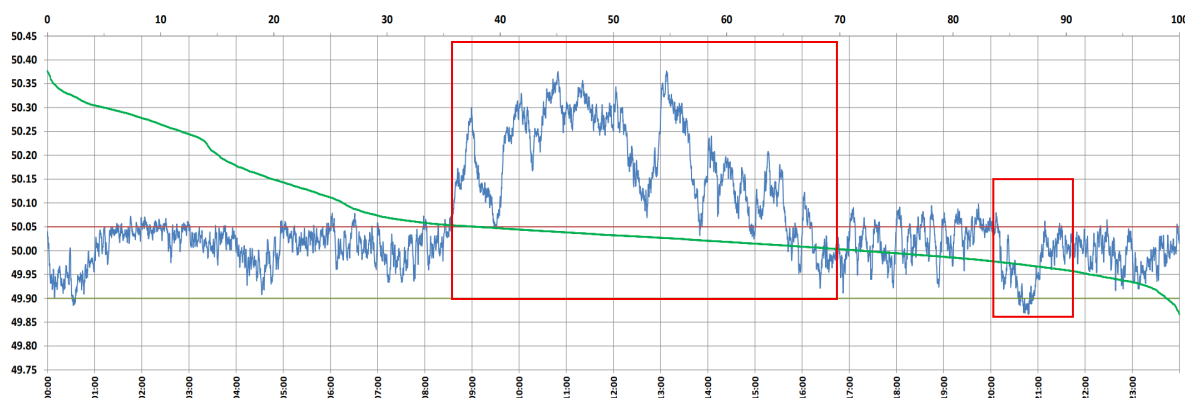
As India scales up renewable capacity towards 2030 and beyond, this episode serves as a critical policy case demonstrating why flexibility must transition from an operational concern to a central design principle of power sector regulation. The frequency profiles under graphs 20 and 21, showcases how the frequency breached the 50.05 Hz upper limit for a prolonged period, with greater breach on 25 August (see *Graph 20: Indian GRID – Frequency Profile: August 4, 2024* and *Graph 21: Indian GRID – Frequency Profile: August 25, 2024*). The frequency breach highlights over-injection into the power grid, i.e., there was more energy in the grid than required.

Graph 20: Indian GRID – Frequency Profile: August 4, 2024



Source: GRID-India – Daily Frequency profile report

Graph 21: Indian GRID – Frequency Profile: August 25, 2024



Source: GRID-India – Daily frequency profile report

Reasons for Event

GRID-India identified multiple system-level factors contributing to persistent high-frequency operations in the Indian power system on 4, 11, and 25 August 2024. The report noted that suppressed demand due to widespread rainfall and weekend effects coincided with higher injection from variable renewable energy sources. At the same time, hydropower and pumped-storage stations provided limited flexibility because of high inflows and reservoir constraints. In the absence of RE curtailment, the RE into the grid resulted in spikes as thermal generating stations exhibited inadequate flexibility. Under-drawal by states from inter-state generation stations, such as those run by NTPC, aggravated the issue. GRID-India also highlighted insufficient liquidity in day-ahead and real-time markets, leading states to commit more generating units than required.

A critical factor identified was the **lack of down reserves at the inter-state level**. Down reserves refer to the ability of a power system to rapidly reduce generation in response to excess supply and curtail power. When adequate down reserves are unavailable, system operators cannot reduce generation quickly enough to match falling demand or rising renewable output, resulting in sustained high-frequency conditions. In this event, the absence of sufficient down reserves constrained GRID-India's ability to balance supply and demand in real time, thereby exacerbating frequency deviations beyond the Indian Electricity Grid Code upper limit of 50.05 Hz.

Over-Injection by ISGS Stations

On **25 August 2024 (12:00–14:00 hours)**, the CERC observed that several inter-state thermal generating stations (ISGS) were scheduled below their MTL but

continued to **over-inject power** to remain near technical operation limit. The Commission's analysis showed that stations such as **Dadri and Darlipali** had schedules below MTL while injecting additional power ranging from **around 59 MW to over 380 MW across 15-minute time blocks**, indicating systematic deviation between scheduled and actual generation. The CERC noted that generators maintain generation near MTL despite lower schedules to remain on-bar and ensure availability for evening peak demand. However, such over-injection during solar hours contributed to excess supply and high-frequency conditions. The Commission highlighted that this pattern reflects structural dispatch challenges, where DISCOMs consume low thermal power during solar hours but rely on thermal generation during evening peaks, leading generators to maintain operations at higher than generation requirements even when scheduled for lower levels.

The incident demonstrates that the current 55 per cent MTL constraint limits the system's ability to absorb high solar generation, reinforcing the policy rationale for accelerating the transition to a 40 per cent MTL across the coal fleet.

NTPC's Operational Concerns

NTPC, India's largest coal-based thermal plant operator company, highlighted that current scheduling practices driven by commercial considerations are creating significant operational risks for thermal power plants. The utility noted that DISCOMs often reduce schedules during solar hours when market prices are low, forcing units to operate at or below minimum technical levels, but then restore full schedules during evening peak hours when market prices rise. NTPC argued that such scheduling patterns disregard the technical constraints of thermal machines and can endanger equipment integrity and asset life due to frequent cycling and rapid load changes.

For example, an 800 MW unit may be backed down to ~440 MW (near or below its MTL) during solar hours and then required to ramp up to its full load of 800 MW within a few hours to meet evening peak demand, placing significant stress on the unit. This challenge is exacerbated when high RE injection results in an operational requirement that falls even lower than the 40 per cent MTL case.

NTPC's concerns underscore the structural mismatch between commercial dispatch decisions and the technical operating limits of coal-based thermal units under rising renewable penetration during the transition period towards flexible thermal power.

2.2 Tools for Frequency Maintenance

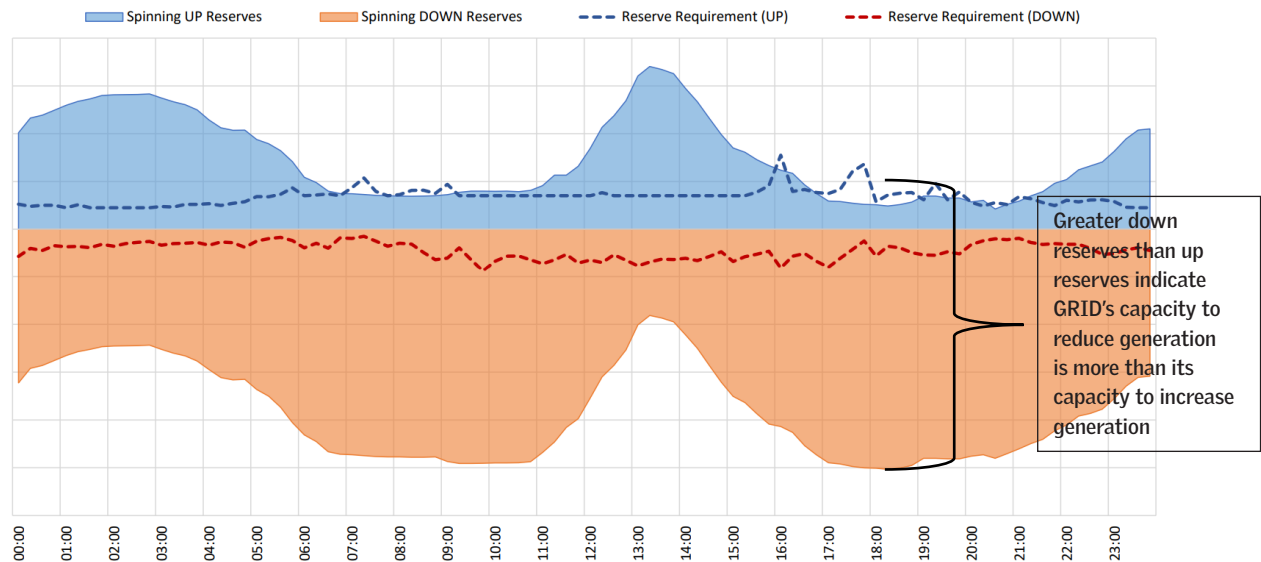
To operationalise policy requirement of frequency maintenance coupled with RE Must-Run in real time, system operators rely on a layered set of scheduling, commitment, and reserve mechanisms to manage uncertainty in demand and renewable generation. Beyond day-ahead schedules, the grid is supported by explicit reserve provisioning and optimisation tools that determine which generators remain online and how much flexible capacity is available at any given time. Two key instruments in this operational framework are the *reserve profile* and the *Security Constrained Unit Commitment (SCUC) mechanism*, which together indicate the system's preparedness to maintain reliability under rising renewable variability.

The **reserve profile** shows how much extra flexibility the power system has to handle sudden changes in supply and demand. Upward reserves are power sources (or demand reductions) that can quickly increase supply when demand rises or renewable generation drops. Downward reserves are the opposite, they help reduce generation when there is excess supply, such as during periods of high solar or wind output. For example, if cloud cover suddenly reduces solar generation in a region, grid operators immediately call on upward reserves, such as ramping up hydro or gas plants, to maintain frequency. Conversely, if wind or solar output suddenly increases beyond forecasts, operators use downward reserves by backing down thermal units or curtailing generation to prevent oversupply.

In Graph 22, the blue shaded area (above zero) represents upward reserves, which indicate the extra power available if demand suddenly increases or renewable generation drops. Conversely, the orange shaded area (below zero) represents downward reserves, which indicate the system's ability to reduce generation when there is an excess supply (see *Graph 22: Indian GRID – Reserve Profile: December 12, 2025*).

In the early morning and late evening, upward reserves are relatively higher, meaning the system is better prepared to meet sudden increases in demand. However, during the afternoon (around 12:00–15:00), upward reserves dip significantly while downward reserves increase sharply. This reflects periods of high solar generation, where the system has excess supply and needs to back down thermal plants. The dashed lines show the required reserves; whenever the available reserves come close to or fall below these lines, it indicates potential stress on system flexibility.

Graph 22: Indian GRID – Reserve Profile: December 12, 2025



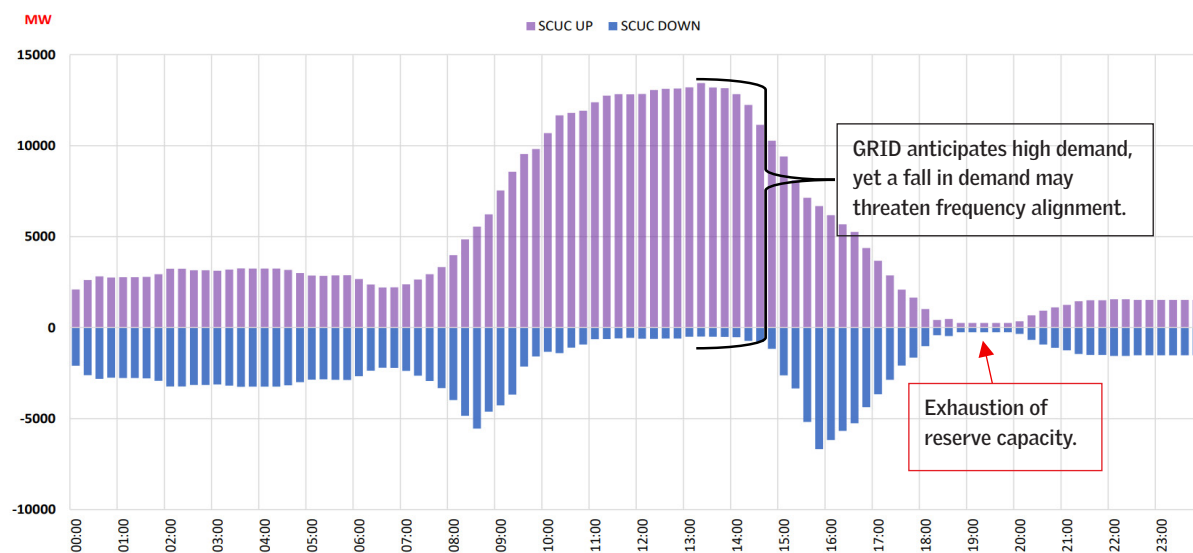
Source: GRID-India's daily report on ancillary services and Security Constrained Unit Commitment (SCUC)

Security Constrained Unit Commitment (SCUC) is a day-ahead optimisation mechanism used by the system operator to commit generating units for energy and reserve provisioning while respecting transmission constraints and technical limits. SCUC ensures that sufficient generation capacity remains online to provide reserves, even if these units are not the most economical to dispatch. In the context of rising renewable penetration, SCUC increasingly commits thermal units to maintain reliability and flexibility, highlighting the growing role of conventional generators in providing balancing and reserve services rather than only energy supply (see *Graph 23: Indian GRID – SCUC Schedule: October 12, 2025*).

The purple bars (SCUC UP) represent the additional generation capacity committed, indicating plants that are kept ready to increase output if demand rises or renewable generation falls. The blue bars (SCUC DOWN) represent the system's ability to reduce generation when there is excess supply.

In the midday period (around 11:00–15:00), upward reserves rise sharply to about 12,000–13,500 MW, reflecting that a large amount of generation is committed and available to increase output if needed. However, during the same period, downward reserves are very limited, staying close to 0 to –1,000 MW. This creates a potential risk, as sudden fall in demand or increase in RE beyond forecasts

Graph 23: Indian GRID – SCUC schedule: October 12, 2025



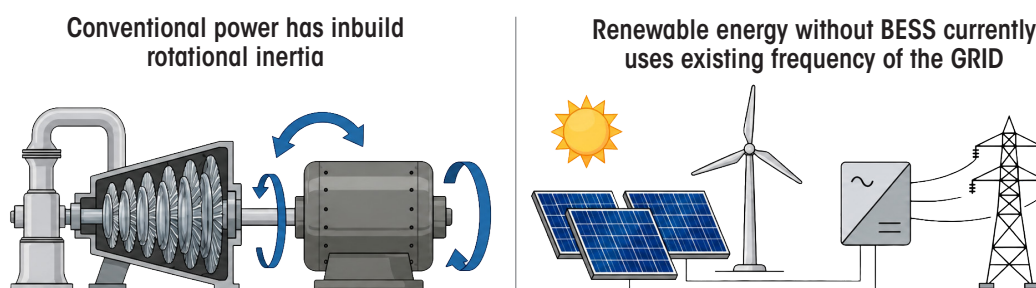
Source: GRID-India's daily report on ancillary services and Security Constrained Unit Commitment (SCUC)

during these hours, the system has very little room to back down generation, increasing the risk of over-injection and frequency rise. A similar tightening is visible in the evening (around 18:00–20:00), where both upward and downward reserves shrink significantly, indicating a constrained system as solar generation drops and demand peaks.

Both these mechanisms are additional support measures, yet they cannot remedy the inherent inflexible generation of the current system, hence the increasing need for flexible thermal power. The issue becomes even more pronounced when viewed alongside the limitations of the current renewable infrastructure, which is discussed in the next segment.

2.3 Limitations of Existing GRID

Conventional coal-based power plants help keep the grid stable because their large rotating machines provide inertia, which resists sudden frequency changes, and they also supply reactive power and fault current, helping maintain voltage and overall system strength. In contrast, renewable energy sources such as solar and wind, which are connected to the grid through electronic systems rather than large rotating machines, do not inherently provide inertia, fault current, or reactive power support. They, therefore rely on conventional thermal power plants to maintain the frequency profile and overall stability of the grid.

Figure 1: Concept of Inertia: Conventional Power vs RE

VRE without BESS lacks inherent inertia, requiring external frequency management

Source: CSE analysis + Google AI illustrator

Thus, higher renewable energy penetration still requires some conventional generation in the grid, as it cannot operate the system independently. At present, the limited deployment of grid-forming inverters at renewable plants or battery storage systems means the grid remains inherently reliant on thermal power to maintain stability (see *Figure 1: Concept of Inertia: Conventional Power vs RE*).

India's grid architecture remains largely **grid-following**, with RE generators reliant on thermal units primarily for shaping voltage, frequency, and system stability. There is a marked lack of **grid-forming capability**, wherein generators can autonomously establish and regulate grid parameters during disturbances or low-inertia conditions.

The rapidly expanding renewable energy fleet—primarily solar and wind—is grid-following, injecting power through power electronic interfaces that require an already stable grid for operation. While renewable energy contributes clean and low-marginal-cost electricity, it does not, in its current form, provide the same level of inertial and frequency support as conventional generation. As renewable penetration increases, this fundamental difference between grid-forming and grid-following resources has become a defining operational characteristic of India's power system. Therefore, in the current form, RE penetration coupled with grid stability requires a flexible thermal generation fleet.

2.4 Key Developments

These developments collectively signal a structural shift in India's power system, where flexibility is emerging as a central requirement for reliable grid operation. The CEA estimates that an aggregate hourly ramping requirement in the Indian power system reached around 250 MW per minute during 2018–2022. Under high renewable energy penetration scenarios, these requirements are projected to increase further to approximately 380–420 MW per minute in the future. Accordingly, the CEA estimated the need of 84 GW of flexible power to integrate 175 GW RE into the system. The policy response to this rising flexibility requirement and its evolution over time is examined in the next chapter.

3

FLEXIBILITY POLICY FRAMEWORK EVOLUTION

India's flexibilisation journey evolved from early efficiency-focused collaborations to a structured regulatory and implementation framework post-2023

CEA's phasing plan encompassed 493 units comprising 196.7 GW, with a timeline of 2024 to 2030

Pilot studies demonstrated technical feasibility of operating at 40 per cent, with best case achieving 34 per cent and ramp rates of 1–3 per cent per minute

CEA's 2026 draft report has found no direct link between flexible operation and plant damage, attributing most failures to ageing, coal quality, and operational practices



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India's policy discourse on thermal power flexibilisation emerged indirectly through early international technical cooperation focused on coal plant efficiency and environmental performance. In the early 2010s, policy frameworks prioritised improving operational efficiency and mitigating environmental impacts, rather than enabling cycling or flexible operations. Over time, the policy approach to flexibilisation evolved and can be categorised into three broad phases. The first phase involved foundational scoping, driven by rising renewable energy penetration and the emerging need to maintain system stability. The second phase focused on expansion and research, with pilot studies and test runs undertaken to assess technical and regulatory requirements for flexible operations in India. The third phase marks the transition towards implementation, culminating in the articulation of a national roadmap and a phased strategy for operationalising flexibility in India's thermal power fleet.

3.1 Phase 1: Foundational Scoping (2010–15)

The scale of RE integration into the generation mix was limited, therefore, early collaborations did not explicitly address flexibility. They established institutional pathways for international technology transfer, plant diagnostics, and data-driven performance evaluation—capabilities that later became central to flexibilisation studies. They also marked the beginning of systematic benchmarking of Indian coal plants against international operational practices.

In **April 2010**, the CEA and the Japan Coal Energy Center (JCOAL) signed their first Memorandum of Understanding (MoU) to study improvement of the thermal efficiency of coal-fired thermal power plants in India and reducing their environmental impact. The JCOAL, since renamed the Japan Carbon Frontier Organization, functions as Japan's central institutional body across the coal value chain, operating under national legal provisions and overseen by the Japanese Ministry of Economy, Trade and Industry (METI). The second phase of the MoU was signed in **June 2012**, to conduct detailed diagnostic studies for energy efficiency-oriented renovation and modernisation (R&M) interventions across three generating units. Field visits were undertaken by the JCOAL team at NTPC's Badarpur and Unchahar thermal power stations in December 2012, followed by submission of the final study report in April 2013.

With the signing of the Paris Agreement in 2015, the pivot towards system resilience to achieve the larger goal of limiting global warming to 1.5°C became paramount. Flexible operation of existing coal-fired plants became a crucial policy goal for ensuring power supply security and grid stability while integrating renewable energy sources.

3.2 Phase 2: Knowledge Building and International Research Cooperation (2016–22)

The journey of regulatory implementation of flexibilisation involved knowledge building on multiple levels owing to various test studies. The process is examined in phases below.

Early Scoping Assessment

India's first concerted step toward flexibility in thermal generation to accommodate RE integration came in May 2016, at the behest of the Ministry of Power, Government of India and the Federal Ministry of Economic Affairs and Energy, Government of Germany. A special task force was constituted under the Indo-German Energy Forum Sub Group-1 to demonstrate the technical and economic capacity for flexible operations, build operational capacity among thermal power plant operators, and analyse legal framework conditions for enabling flexibility. As part of the technical and economic assessment, NTPC Dadri and Simhadri were selected as reference plants. The task force undertook capacity-building activities for plant operators, including study tours to Europe and related workshops. It also analysed the prevailing legal and regulatory framework and provided recommendations to support flexible operation of thermal power plants. The task force submitted its final report to the CEA in 2017. The technical association of energy plant operators, VGB (now known as VGBe), participated in the task force and recommended technical measures for three operational scenarios—a 50 per cent minimum load with no investment, a 40 per cent minimum load with moderate investment, and a 25 per cent minimum load with high investment.

The task force recommended a minimum load of 50 per cent for all thermal power stations in India and proposed the phased implementation of a 40 per cent minimum load, starting with subcritical units across state, independent power producers (IPPs), and central generating stations. It also recommended start-up optimisation and the installation of condition monitoring equipment to sustain flexible operations—with initial implementation in subcritical units and subsequent extension to other units—while highlighting the significant role of original equipment manufacturers (OEMs). The task force considered achieving a 25 per cent minimum load to be unfeasible due to the requirement for very high-quality coal and the need for further studies. In its annexure, the task force outlined technical measures for achieving a 50 per cent minimum load, including reassessment of operation and maintenance procedures, optimisation of automation and controls, evaluation of boiler and turbine process limitations in cooperation with OEMs, test runs to assess flexibility potential, and consideration of part-load operation in flue-gas equipment design.

Advancing the Paris Agreement commitments in India's power sector, the CEA formed a committee in February 2018 to address the challenges of integrating 175 GW of renewable energy, a target later expanded to achieving 50 per cent or more of non-fossil capacity. The high scale of RE into the grid lead to early net load swing of up to 80 GW by 2021–22, and necessitated coal-based TPPs to operate at a minimum load dipping as low as 25.73 per cent.

However, the committee deemed operating coal units below 35 per cent as technically improbable and financially unviable, particularly due to the high ash content of Indian coal. To maintain grid stability without pushing TPPs past this limit, the committee recommended a multi-pronged approach centred on coordinated generation.

Pilot Studies

Flexibility studies are required because India's coal-fired power plants were designed for steady base-load operation, whereas the rising penetration of variable renewable energy requires frequent load cycling and rapid output adjustments. Before mandating flexible operations, policymakers needed evidence on whether existing plants could technically operate at low-load levels, how quickly they could alter power output, and what operational risks low load operations will create.

The pilot tests therefore evaluated five core parameters that describe how a power plant behaves under flexible operations:

- i. **Minimum load**, which indicates the lowest power level at which a plant can run safely without shutting down;
- ii. **Ramp-up rate**, which measures how fast a plant can increase electricity generation to respond to rising demand or falling renewable output;
- iii. **Ramp-down rate**, which measures how fast it can reduce generation when solar or wind output rises;
- iv. **Operational stability at low-load**, which captures whether combustion, steam temperature, and water levels remain stable when the plant runs far below its design output; and
- v. **System and equipment response**, which assesses whether turbines, boilers, and control systems can handle frequent load changes without damage or efficiency losses.

Together, these parameters provide empirical evidence on whether India's coal fleet can support renewable integration without compromising grid stability or plant safety, thereby informing subsequent regulatory and technical recommendations on flexibilisation. This is essential as thermal units have both

commercial and machine capability aspect. Machine capability becomes key in India's case, as flexibilisation will largely be in the form of retrofitting on existing units. Additionally, thermal machines have a higher thickness that causes temperature exertion when operational load is altered. Altering it too quickly can lead to cracking in some cases, a risk that must be understood.

The test parameters can eventually be condensed on the following five aspects.

Table 3: Pilot Test: Parameters for Flexible Operations

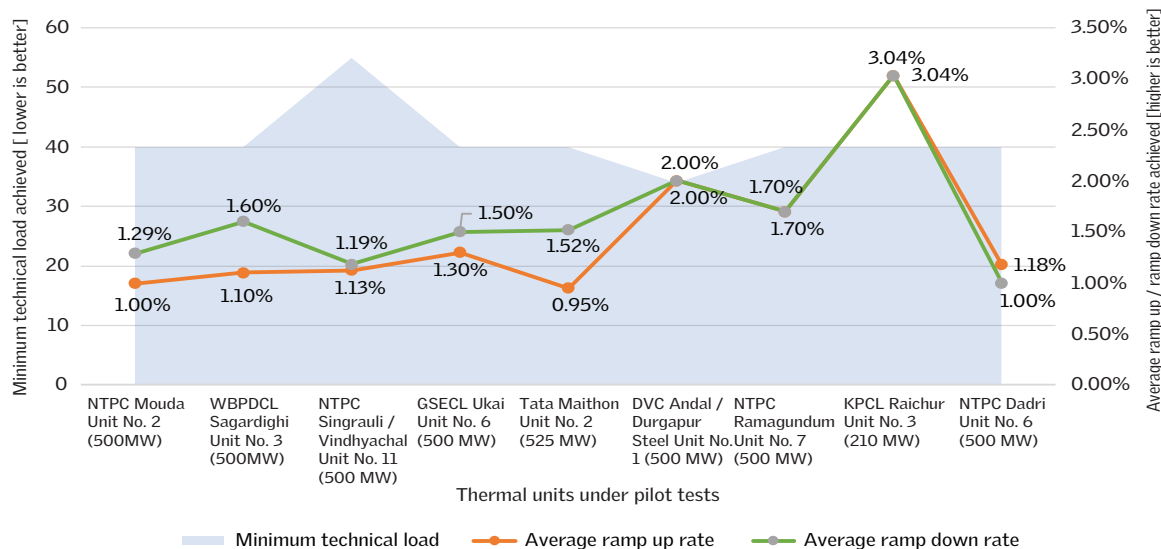
Parameters	Target
Minimum load test	40 per cent of the unit's capacity
Ramp-up test	3 per cent per minute
Ramp-down test	3 per cent per minute
Ramp-up test	1 per cent per minute
Ramp-down test	1 per cent per minute

Source: CEA Flexibilisation of Coal fired Power Plant Report, February 2023

Ramp-up and ramp-down tests were varied across multiple parameters to test the technology-wide capacity assessment of thermal units during different operational loads. The common understanding during the early studies was that the MTL was limited for Indian coal units owing to high ash content in Indian coal. Consequently, the capacity to ramp up or down from different technical loads was being assessed during the pilot runs.

The pilot flexibilisation studies demonstrated that several Indian coal-based thermal units are technically capable of operating under flexible regimes, though with heterogeneous performance across units and parameters. Most units successfully achieved the targeted **minimum load of 40 per cent of rated capacity**, with some outperforming this benchmark, such as DVC Andal/Durgapur Steel Unit No. 1 operating at **34 per cent minimum load**. However, one unit (NTPC Singrauli/Vindhyachal Unit No. 11) was only able to reach **55 per cent minimum load**, highlighting plant-specific constraints related to boiler design, coal quality, and operational practices. These findings covering subcritical thermal units, which constitute the majority portion of the Indian coal fleet, provided early empirical evidence that MTL reduction is feasible in Indian coal plants but not uniformly achievable without targeted retrofits and operational modifications.

Graph 24: Test Run Performance on Flexibilisation



Source: CSE analysis of CEA's Flexibilisation of Coal fired Power Plant Report, February 2023 + CEA's Quarterly Review Report Renovation & Modernisation of Thermal Power Stations, July/September 2025

In terms of ramping capability, the pilot units exhibited a wide range of ramp-up and ramp-down rates. Several units met or exceeded the **3 per cent per minute ramping target**, with DVC Andal/Durgapur and KPCL Raichur achieving ramp rates of up to **2–3.57 per cent per minute**, indicating strong flexibility potential. Others showed moderate performance, with ramp rates between **0.95–1.68 per cent per minute**, suggesting partial compliance with flexibility benchmarks. Tests conducted at the **1 per cent per minute ramping regime** confirmed that most units could reliably operate under slower cycling conditions, providing a practical baseline for early-stage flexibilisation.

Graph 24 showcases the entire pilot test study and the parameter achievement across the units at a glance. Overall, these pilot studies established that **40 per cent MTL operation was technically achievable** in selected units, although with plant-specific control system tuning and operational adjustments. They also validated ramping capabilities in the range of **1–3 per cent per minute**, providing empirical benchmarks for flexible operation.

Conclusively, the pilot studies confirmed the technical feasibility of coal plant flexibilisation in India, while also revealing significant variability across units, underscoring the need for plant-specific retrofits, operational guidelines, and financial support mechanisms to scale flexibilisation across the national fleet.

National Electricity Plan (NEP) 2022–23

As pilot studies progressed, flexibility considerations began to be integrated into national power system planning frameworks. National Electricity Plan (NEP) exercises and Integrated Resource Planning (IRP) modelling incorporated flexibility requirements into long-term capacity expansion scenarios.

The Committee for Preparation of NEP 2022–32 established multiple sub-committees to examine sectoral dimensions, including a dedicated Sub-Committee No. 10 on Flexible Resources for Grid Stability.

The Sub-Committee’s terms of reference included assessing the need for flexible resources to ensure grid stability, identifying available options—such as energy storage systems—to improve operational performance and maximise renewable energy utilisation, and developing a future roadmap for integrating these storage solutions. It also aimed to create a roadmap for achieving maximum renewable energy penetration through flexible operations of conventional generating units, while balancing grid stability, security, reliability, and cost constraints. The NEP projected all-India peak demand of **277.2 GW by 2026–27** and **366.4 GW by 2031–32**, with energy requirements increasing from **1,907.8 BU to 2,473.8 BU** over the same period.

The NEP signalled a shift from flexibility as an operational experiment to a strategic planning priority. It marked an important evolution in India’s policy discourse, integrating thermal flexibility into long-term capacity expansion and system reliability frameworks, rather than treating it as a purely technical or pilot-driven intervention.

3.3 Phase 3: Institutionalisation of Flexibility into Operations (2023 Onwards)

Building on the strategic recognition of flexibilisation via pilot studies, the CEA operationalised flexibility objectives through a phased implementation roadmap, outlining technical benchmarks, timelines, and retrofit pathways for the existing coal fleet. This policy trajectory was further translated into regulatory action during 2023–2025, when flexibility norms, minimum load thresholds, and ramping requirements were formalised through technical guidelines and regulatory instruments to mainstream flexible thermal operations in India’s power system.

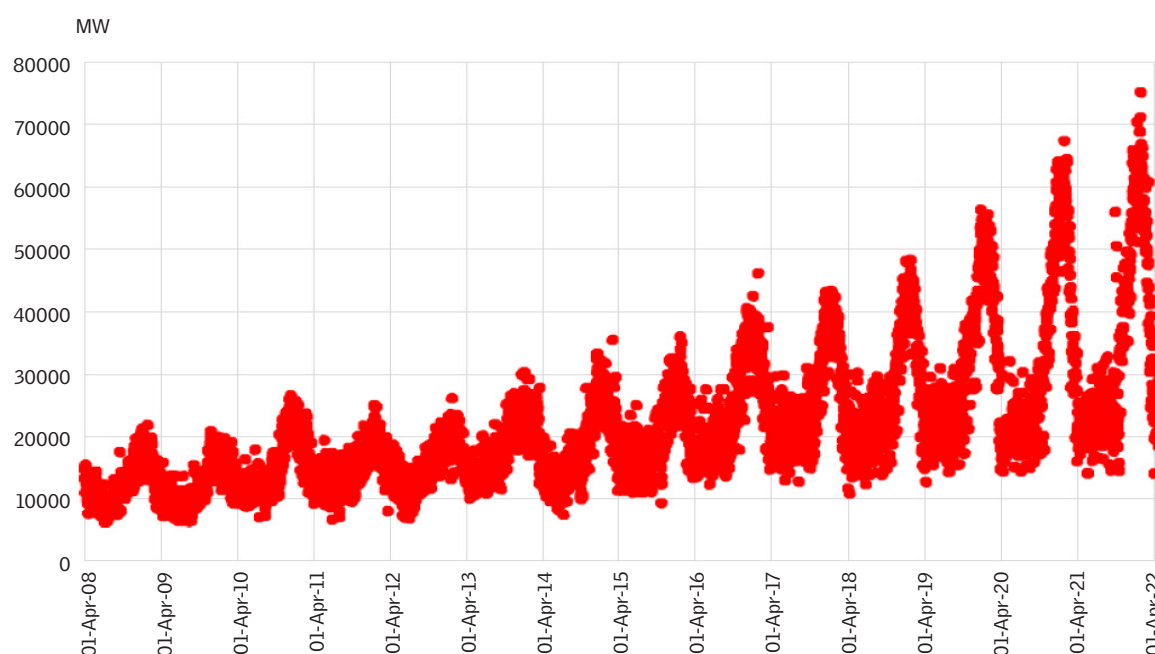
CEA Flexibilisation Roadmap, 2023

In order to operationalise policy commitments on thermal flexibility, the CEA released the *Roadmap for Achieving 40 Per cent Technical Minimum Load* in

2023, providing a structured technical and implementation framework for central, state, and private coal-based thermal power utilities.

The *CEA's Roadmap for Achieving 40 Per cent Technical Minimum Load (2023)* marked a decisive step in institutionalising flexibilisation within India's power sector operational framework. The report explicitly linked flexibilisation to India's national climate commitments, including the target of achieving 40 per cent non-fossil fuel installed capacity by 2030 and reducing emission intensity by 33–35 per cent from 2005 levels. It recognised that rising penetration of renewable energy, estimated at 454 GW of renewables within a projected total installed capacity of 838.8 GW by 2029–30, will fundamentally alter the operational paradigm of coal-fired power plants, requiring them to operate at lower minimum loads and higher ramping rates to ensure grid stability. Given that thermal generation constituted 54 per cent of installed capacity and met more than 70 per cent of electricity demand, the report framed flexible operation of coal-fired plants as essential for managing variability and intermittency in renewable generation and maintaining system reliability.

Graph 25: Difference Between All India Daily Maximum and Minimum Demand (April 2008–May 2022) (in MW)



Source: CEA Roadmap for Flexibilisation, February 2023

The roadmap translated the strategic need for flexibility for grid stability into operational and regulatory benchmarks, thereby anchoring flexibilisation as a core future requirement of the Indian power system. It set 40 per cent MTL as a central operational target and assessed system-level ramping requirements, noting that maximum ramp-up and ramp-down requirements could reach 379 MW/min and 422 MW/min respectively for 175 GW of renewable capacity, with future ramping needs potentially increasing to 1.5–2 per cent per minute under a 500 GW renewable scenario. The document also estimated a requirement of 84 GW of flexible thermal power to integrate 175 GW of renewables, highlighting the scale of flexibility needed from the coal fleet. By outlining technical benchmarks, retrofit needs, and implementation timelines, the roadmap effectively served as the policy-technical blueprint for subsequent regulatory instruments, embedding flexibilisation into the operational logic of India's electricity sector and signalling its centrality in future power system planning and regulation.

CEA Flexible Operations Regulations, 2023

In order to translate policy intent and technical roadmaps into binding legal obligations, the Government of India notified the *Central Electricity Authority (Flexible Operation of Coal Based Thermal Power Generating Units) Regulations, 2023* under Sections 73 and 177 of the Electricity Act, 2003 on 25 January 2023.

Under *Regulation Three*, the regulations apply to all coal-based thermal power generating units owned or controlled by the central government, state governments, or private companies, and to all load despatch centres connected with the grid. The regulations mandate that generating units be designed or suitably retrofitted to comply with flexibility requirements across site-specific environmental conditions, thereby formally embedding flexibilisation into the operational and technical compliance framework of India's power sector. The regulations codify key technical flexibility parameters and establish a phased compliance pathway.

Regulation Six mandates that coal-based generating units achieve a minimum power level of 40 per cent for flexible operation, with interim compliance requirements for units currently operating above this threshold, including a requirement to achieve 55 per cent minimum load within one year if not already capable. *Regulation Seven* specifies ramp rate capabilities of at least 3 per cent per minute between 70–100 per cent load, 2 per cent per minute between 55–70 per cent load, and 1 per cent per minute between 40–55 per cent load, with phased implementation linked to the Authority's rollout plan under *Regulation 5(2)*.

Table 4: Ramp Rate Requirement Under Regulations, 2023

Load Range	Minimum Ramp Rate (Up/Down) Requirement
70–100 per cent load	≥ 3% per minute
55–70 per cent load	≥ 2% per minute
40–55 per cent load	≥ 1% per minute

Source: Central Electricity Authority Regulations, 2023

Additionally, *Regulation 5(3)* requires load despatch centres to consider flexible operation capabilities in scheduling decisions, thereby integrating flexibility into system operations and dispatch protocols. Collectively, these provisions formalise flexibilisation as a statutory operational requirement rather than a voluntary or pilot-based practice, positioning flexible thermal operation as a core pillar of India’s evolving power system architecture.

Notably, the regulations apply specifically to units covered under the phasing plan and did not update the standards for under-construction or newly approved coal-based thermal units. This exemption leaves out units built or coming into operation after the regulations came into force.

CEA Phasing Plan for Flexible Operations, 2023

Pursuant to the *Central Electricity Authority (Flexible Operation of Coal Based Thermal Power Generating Units) Regulations, 2023*, the CEA issued a detailed **phasing plan for implementation of 40 per cent MTL** to operationalise regulatory flexibility mandates across the coal fleet. The phasing plan is issued under the CEA’s mandate to specify timelines and technical pathways for compliance and applies to central, state, and private coal-based thermal power generating units and system operators, with implementation to be carried out by generating companies and overseen by load despatch centres and sector regulators.

The plan explicitly recognises that flexibilisation must be implemented sequentially due to heterogeneity in plant design, age, location, fuel characteristics, and control technologies, and therefore proposes a **pilot phase followed by four structured implementation phases** based on commissioning year, renewable energy concentration, and technical feasibility considerations, such as boiler type and milling systems.

Table 5: India: Phase-Wise Implementation Timeline and Coverage of Flexibilisation Programme

Phase	Timeline	Number of Units Covered	Capacity Covered (in GWs)
Pilot Phase	May 2023–December 2023	10	5.85
Phase 1	July 2024–March 2026	91	51.08
Phase 2	July 2026–March 2028	100	46.82
Phase 3	July 2028–December 2029	101	37.21
Phase 4	January 2030–December 2030	191	55.76
Total	2024–30	493	196.7

Source: CEA Phasing Plan, 2024

By providing timelines, unit-level coverage, and technology-specific sequencing, the phasing plan functions as the implementation backbone of India's flexibility regulatory framework, signalling a transition from voluntary pilots to system-wide operational mandates. The phasing plan is examined in detail and its on-ground implementation is evaluated in Chapter 5.

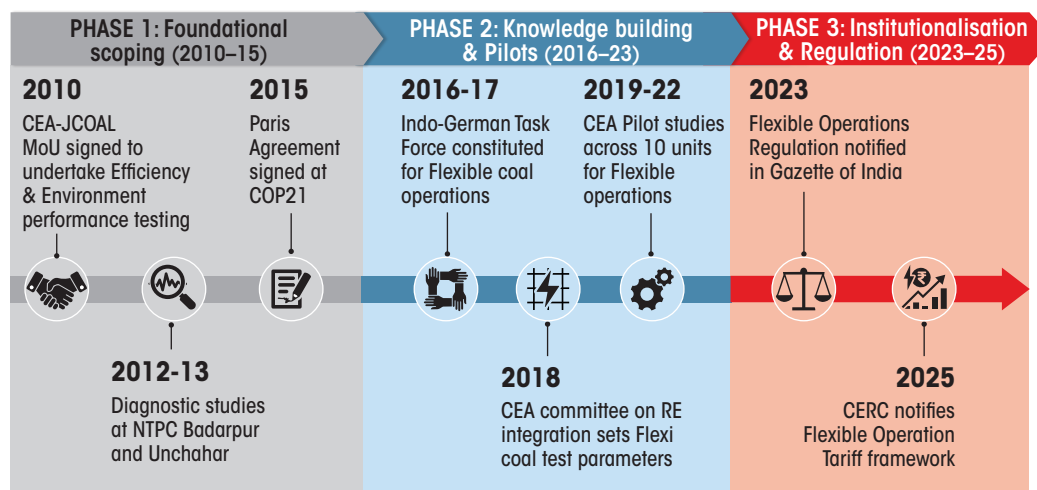
CEA Draft Report on Wear & Tear, O&M and Plant Lifespan Implications due to Flexible Operations, 2026

After the GRID-related incidents mentioned in Chapter 2 and the pilot runs conducted over the past time period, the CEA constituted a committee in 2025 to examine the implications of flexible operations and two-shift operations, especially related to wear and tear, operation and maintenance (O&M) costs, and plant lifespan of coal-based thermal power plants. The committee reviewed operational data, including case studies from NTPC units and captive power plants operating under low-load conditions. The committee report mentioned that the original equipment manufacturer (OEM) provider, BHEL, reviewed unit data and found no direct correlation between the outages suffered during the assessed time-period attributable to low-load operations or frequent ramping. As per the report, among the assessed units, a majority of the observed failures were linked to factors such as ageing or operating units beyond their operational life span, inconsistent coal usage, and other operational practices. BHEL observed that damages can also be attributed to lower load operations if they lack the necessary retrofits required for low-load flexible operations. The report re-emphasised that flexible operation below 55 per cent MTL is technically feasible with appropriate retrofits and control modifications, and may be less damaging than frequent shutdowns due to low power demand during daytime. It has suggested the need for pilot studies for two-shift operations in

older units—especially those older than 40 years and above—to generate empirical data and inform compensation mechanisms. The next step involves assessing the availability and suitability of units for two-shift operations before finalisation of their compensation mechanism. Overall, the report underscores that enabling thermal flexibility is essential for integrating renewable energy while maintaining grid reliability. It further emphasises that necessary test runs are still required to clearly determine tariff compensation for flexible operations.

Moving ahead, while the policy and regulatory instruments institutionalised flexible operation in technical and operational terms, their implementation is contingent on cost recovery mechanisms and tariff treatment for retrofitting and operational efficiency losses. *Chapter 4* examines the policy history of cost assessments and tariff frameworks for flexibilisation in India, analysing how regulatory economics is shaping the feasibility of flexible coal operations.

Figure 2: Timeline of Indian Flexibilisation Policy



Source: CSE analysis

4

ROLE OF COST AND TARIFF POLICY

Flexibilisation CAPEX is estimated at Rs 6–30 crore per unit, recoverable through fixed cost pass-through over a five-year period

CERC's tariff framework allows part-load compensation, but only five of 15 State GENCOs have incorporated flexibility tariff, creating an asymmetric coverage

Flexible operations increase OPEX by 8–15 per cent per unit, driven by heat rate degradation, greater auxiliary consumption, and equipment life consumption

Section 62 frameworks and limited Section 63 applicability exclude cycling, start-up stress, and retrofit costs, creating financial gaps for flexible operations



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With greater renewable energy (VRE) penetration, the operational role of coal-based thermal power plants is undergoing a structural transition, from base-load generation to balancing and system support. In this context, flexibilisation costs represent **upgradation and adaptation costs** required to keep existing thermal assets technically functional, system-relevant, and economically viable over their remaining operational lifespan. Rather than being discretionary efficiency investments, these costs reflect a necessary transformation of legacy infrastructure to align with a power system increasingly characterised by variability, uncertainty, and rapid net-load changes.

The CEA's studies indicate an estimate that **40 per cent MTL operation can increase total tariffs (fixed and variable) by around 7–8 per cent**, with potentially higher impacts for older units. The studies showcase that efficiency degradation, increased O&M, and retrofit costs collectively contribute to tariff increases, although plant-specific feasibility studies are required to determine precise cost impacts. These findings underscore that flexibilisation is not cost-neutral and requires regulatory mechanisms for cost recovery, particularly as flexibility is mandated for system-level renewable integration, rather than generator-driven commercial decisions.

Chapter 4 examines the economic and regulatory dimensions of coal plant flexibilisation, focusing on how technical flexibility mandates translate into costs and tariff frameworks. Building on the policy and institutional evolution outlined in Chapter 3, this chapter first traces engineering and system-level cost assessments undertaken during early flexibilisation studies and identifies the key cost elements associated with flexible thermal operation. It then analyses how these costs have been recognised and operationalised through tariff regulations issued by the Central Electricity Regulatory Commission (CERC), including the evolution from generic capital cost recognition to detailed compensation mechanisms for operational efficiency losses, auxiliary consumption, and secondary fuel oil use. The chapter further examines how State Electricity Regulatory Commissions (ERCs) have adopted diverse approaches to flexibilisation compensation, leading to fragmented regulatory practices across jurisdictions, including an assessment of regulatory coverage across India. Finally, the chapter evaluates the differential treatment under Sections 62 and 63 of the Electricity Act, 2003, highlighting how cost-plus and competitively bid procurement frameworks shape incentives, risk allocation, and cost recovery for flexible thermal operations in India.

Consequently, flexibilisation expenditures, covering retrofits, efficiency losses, increased maintenance, and asset life impacts are to be interpreted as transition costs that enable thermal units to continue providing reliability, ramping, and reserve services in a high-renewable electricity system, thereby safeguarding system stability and protecting the value of sunk capital in the existing coal fleet.

4.1 Cost Assessment on Flexibilisation

This section first examines the elements of cost consideration for flexibilisation before analysing the exact cost estimates highlighted by the various studies conducted.

Elements for Consideration Under Cost Component

The institutionalisation of flexible operation in India's coal fleet has been accompanied by a growing body of technical studies assessing the associated capital and operational cost implications. The CEA's monitored studies synthesise the elements which ought to be considered for flexibilisation. These include OEM assessments via engineering evaluations to identify multiple cost categories linked to retrofitting, efficiency losses, maintenance impacts, and plant life degradation. The cost assessments highlighted via the studies were indicative in nature and were derived from pilot test results during low-load plant behaviour under cycling operations.

Capital Expenditure for Retrofit and Control System Modifications

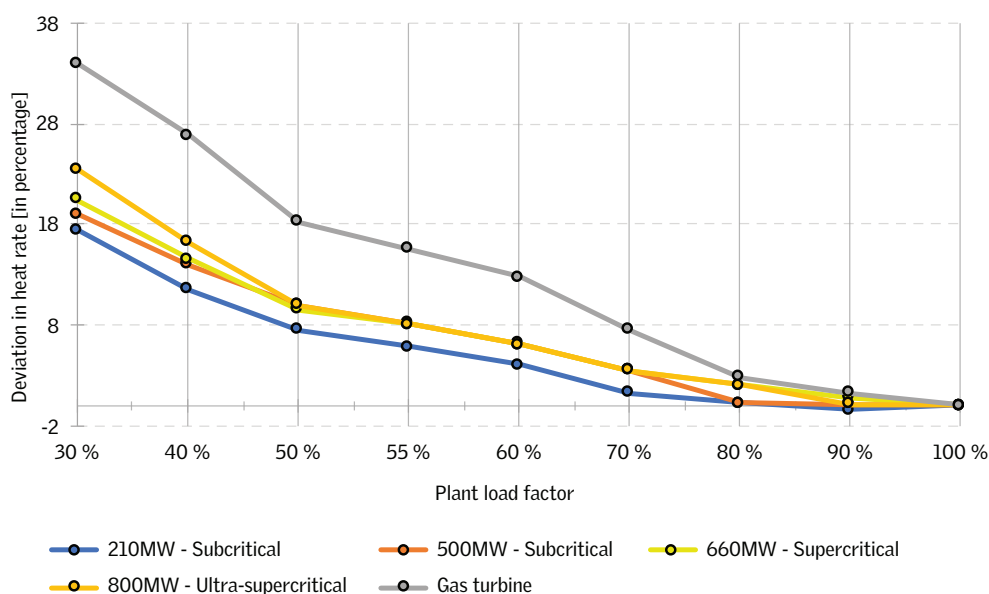
The foremost element for consideration is the **capital expenditure (CAPEX)** associated with retrofitting coal units to enable stable low-load and ramping operations. These costs arise from required **hardware and control system upgrades**, including advanced process control tuning, mill automation, installation of additional sensors, combustion monitoring systems, variable frequency drives, and modifications to auxiliary systems, such as pumps and fans. The need for such retrofits was identified when during the pilot tests, manual interventions were required during ramping and low-load operations, indicating insufficient automation and control system responsiveness.

Technical assessments further highlighted that base-load designed units have control systems optimised for 60–100 per cent load operation, making control at lower loads poor and sluggish. As a result, upgrades to control and instrumentation systems, alarm logic, and protection settings were recommended to safely enable flexible operation, implying significant upfront capital investment, especially for legacy units.

Efficiency Losses and Heat Rate Degradation Costs

A major challenge for flexibilisation cost is the **efficiency degradation during part-load and cycling operations**. Operating coal units at low loads leads to increased net heat rate, higher auxiliary power consumption, and reduced thermal efficiency, which directly increases variable generation costs. One can understand this by noting the cost of an eight-lane highway that is only being used at its optimum capacity for a couple of hours of the day, leading to incurred cost overruns in general.

Graph 26: Percentage Deviation of Net Heat Rate at Various Load Conditions



Source: CEA Roadmap for 40 per cent Technical Minimum Load

The studies identified deterioration in efficiency as a major **cost component associated with low-load operation**. Improving part-load efficiency through operational modifications can have short payback periods, allowing for reduced cost expenses in the long run. Pilot tests and engineering studies demonstrated that heat rate increases significantly at lower loading factors, particularly under fixed-pressure operation, while sliding pressure operation can mitigate some efficiency losses.

Notably, the pilot studies were undertaken on subcritical units, hence ultra and supercritical units may face additional efficiency related challenges when operating them under lower minimum technical loads.

Increased Operation and Maintenance (O&M) Costs

A structural consequence of flexible operations **are the increased O&M costs**. Cycling operation accelerates wear and tear of critical components—such as mills, boiler pressure parts, valves, and auxiliary equipment—requiring more frequent inspections, maintenance interventions, and spares replacement. These impacts were observed during pilot studies and are expected to increase equivalent forced outage rates and maintenance expenditure over the unit's lifetime. Flexible operation also increases costs associated with start-up fuel, auxiliary power consumption, chemicals, water use, and manpower due to frequent start-stop cycles. These operational costs are recurrent and form part of fixed and variable tariff components, thereby influencing generation economics. Manufacturers of new and upcoming coal units ought to use the studies as a benchmark to upgrade designs and improve future units wherein these challenges can be minimised.

Plant Life Consumption and Asset Degradation Costs

One of the critical but often unpriced cost of flexibilisation is the **accelerated plant life consumption**. Nominally, coal units have an expected lifespan of 25–40 years, with some Indian units currently operating beyond this life cycle and yet performing effectively. Investment by companies into the unit is based on similar lifespan assessment. Frequent load cycling induces creep-fatigue damage due to thermal stresses, particularly in thick-walled components, such as headers, turbine rotors, superheaters, reheaters, and welded joints. Pilot studies reported increased corrosion, erosion, fatigue cracking, temperature excursions, and steam chemistry disturbances, all of which contribute to accelerated degradation of plant assets.

These degradation mechanisms increase overhaul capital expenditure, reduce asset lifetime, and raise replacement energy costs due to higher forced outage rates. Consequently, flexible operation entails long-term capital recovery and reliability costs that extend beyond immediate operational expenditure.

Cost of Flexible Power

Flexible operation of coal-based thermal power plants introduces a range of capital and operational costs that were assessed through pilot studies, engineering analyses, and international benchmarking exercises. These elements have been noted in the previous segment of the chapter referred above. These cost assessments provide early empirical evidence on how flexibilisation alters the economics of thermal generation and inform regulatory deliberations on tariff treatment and cost recovery mechanisms. This section examines the cost estimates under various elements as suggested by CEA.

Capital Expenditure (CAPEX)

The CAPEX requirements are primarily associated with retrofitting and upgrading existing thermal units to enable low-load and cycling operation. The CEA Roadmap synthesises multiple engineering and pilot studies to estimate the capital expenditure required to retrofit coal-based thermal power plants for flexible operation. These studies highlight that CAPEX requirements vary significantly by unit age, technology, and flexibility depth, with deeper flexibility (below 40 per cent minimum load and frequent cycling) requiring higher interventions.

The CAPEX leads to modifications to control systems, installation of advanced instrumentation and monitoring systems, boiler fatigue monitoring systems, and automation upgrades for auxiliaries such as pumps and fans. Overall, these studies distinguish between firstly, CAPEX for enabling flexible operation and secondly, CAPEX for repairing accumulated damage due to cycling, highlighting that flexibilisation requires both upfront adaptation investment and ongoing capital recovery for accelerated asset degradation.

The IGEF-supported task force estimated one-time retrofit costs for enabling low minimum load operation at NTPC Dadri (210 MW) and Simhadri (500 MW). The study estimated Rs 3.9–7.8 crore per unit for achieving 40 per cent technical minimum load, Rs 2.25–7.8 crore for start-up optimisation, and Rs 0.65–1.95 crore for managing cycling-related damage. The study noted that costs increase significantly for operating below 40 per cent load, reflecting rising technical complexity and risk mitigation requirements.

Table 6: Study-Wise CAPEX Estimates for Flexibility Retrofits

Study/Source	Plant/Scope Covered	Estimated CAPEX (per unit)
IGEF Task Force Study (2017)	NTPC Dadri (210 MW) and NTPC Simhadri (500 MW)	• Rs 3.9–7.8 crore for achieving 40% MTL • Rs 2.25–7.8 crore for start-up optimisation • Rs 0.65–1.95 crore for managing cycling-related damage
Siemens Study	NTPC Dadri and Simhadri	Rs 20–50 crore for implementing flexibility measures (advanced control, fatigue monitoring, automation, milling optimisation)
General Electric (GE) Study	NTPC Talcher	Rs 20–50 crore for advanced control system upgrades and operational optimisation measures
Engie Study	NTPC Dadri and Farakka	• Rs 3.2–5.6 crore for extended load-following at 40% MTL • Rs 4.1–8 crore for frequent warm starts
NTPC Actual Retrofit (2019)	NTPC Dadri 500 MW Unit	Rs 5.5 crore for basic flexibilisation retrofits (temperature control, milling automation, fatigue monitoring, auxiliary automation)

Source: CSE analysis of CEA reports

The Siemens study ran parallel to the IGEF one and, based on proposals for flexibilisation at NTPC Dadri and Simhadri, estimated Rs 20–50 crore per unit for implementing a suite of flexibility measures. These included temperature optimisation systems, fatigue monitoring systems, equivalent operating hour counters, control loop optimisation, boiler feed pump recirculation valves, automated fan and pump operation, and mill scheduling systems. *US based General Electric (GE)* provided similar estimates for implementing flexibilisation measures at NTPC Talcher, with indicative capital costs of Rs 20–50 crore per unit, reflecting advanced control system upgrades and operational optimisation measures required for flexible operation. *France based Engie's* assessment for NTPC Dadri and Farakka estimated Rs 3.2–5.6 crore per unit for extended load-following with a 40 per cent minimum load, and Rs 4.1–8 crore per unit for frequent warm starts, highlighting the incremental capital costs associated with cycling capability beyond basic low-load operation.

NTPC's actual retrofit implementation at Dadri 500 MW unit in 2019 included predictive main steam temperature control, reheater temperature control, modulating boiler feed pump recirculation valves, milling system automation, flue gas temperature control, automated fan operation, and boiler fatigue monitoring systems. The total capital expenditure for these retrofits was around **Rs 5.5 crore per unit**, providing an empirical benchmark for basic flexibilisation upgrades.

Collectively, these studies provide indicative early-stage estimates of capital expenditure for coal plant flexibilisation, largely based on pilot interventions and OEM proposals from the late 2010s and early 2020s. Given inflation, technology cost escalation, and deeper flexibility requirements anticipated under higher VRE penetration, actual retrofit costs are likely to be higher in future implementation phases.

Operational Expenditure (OPEX)

The CEA Roadmap categorises operational expenditure impacts into three broad components—increased fuel costs due to efficiency degradation, increased maintenance costs due to accelerated component wear, and increased oil consumption due to higher forced outage rates.

Studies conducted at Ramagundam, Jhajjar, and Ukai plants under the USAID GTG-RISE programme, with technical support from Intertek AIM (US), provided empirical estimates of life consumption and maintenance impacts under cycling operation. These studies indicated that shifting from base-load to flexible operation

accelerates creep and fatigue damage in boiler and turbine components, leading to higher maintenance frequency and forced outage rates.

International benchmarking by Engie Lab estimated that **capital and additional maintenance costs could result in a 0.3–4.3 per cent increase in total unit costs**, equivalent to **Rs 0.01–0.15 per kWh**, depending on the frequency and depth of cycling events. These findings highlight that OPEX impacts are event-driven and increase significantly with deeper and more frequent flexibility requirements.

Net Heat Rate Degradation Costs

Net Heat Rate degradation constitutes a structural cost of flexible operation, as coal units are thermodynamically optimised for base-load operation and exhibit declining efficiency under low-load and cycling regimes. These findings provided early quantitative evidence to regulators that flexible operation would increase variable generation costs and require tariff recognition mechanisms for efficiency-related cost recovery.

Engineering assessments, based on combustion engineering boiler design and GE turbine configurations, were used to estimate the relationship between load level, heat rate deterioration, and tariff impact. These estimates assume **a base Energy Charge Rate (ECR) of 200 paisa/kWh**, derived from the average ECR of NTPC stations during April–October 2018.

The analysis shows that NHR deterioration increases sharply as unit loading decreases, with higher degradation at deeper part-load levels. For 200/210 MW units, NHR degradation was estimated at 1.1 per cent at 70 per cent load, 3.8 per cent at 60 per cent load, 7.5 per cent at 50 per cent load, and 11.6 per cent at 40 per cent load, corresponding to an additional 2.1 to 23.2 paisa/kWh in variable costs. For 500 MW units, degradation was higher, reaching 13.8 per cent at 40 per cent load, with an incremental variable cost of 27.6 paisa/kWh. Similarly, 660 MW units exhibited 14.4 per cent degradation at 40 per cent load, increasing variable costs by 28.7 paisa/kWh. At very low-load levels of 30 per cent, degradation exceeded 17–20 per cent across unit sizes, resulting in additional costs of 34.6 to 40.8 paisa/kWh.

These estimates indicate that **larger units experience higher absolute efficiency losses at part-load**, although smaller units also incur significant degradation at deeper flexibility levels. The relationship between loading factor and NHR deterioration highlights a non-linear cost curve, with marginal efficiency losses increasing disproportionately at lower loads.

Damage Costs Owing to Accelerated Asset Life Consumption

Flexible operation introduces additional damage costs due to increased thermal cycling, which accelerates creep-fatigue damage in thick-walled components, such as headers, rotors, and boiler pressure parts. Coal-based thermal units are designed for base-load operation with defined creep and fatigue life limits; shifting to cycling operations consumes these life limits at a faster rate. Consequently, plants operated on daily or weekly start-stop cycles experience significantly higher maintenance and replacement costs.

USAID–Intertek RISE study assessed increased O&M and capitalised maintenance costs at NTPC Ramagundam, NTPC Jhajjar, and GSECL Ukai, based on five to

IMPACT OF LOW-LOAD OPERATION ON TARIFFS: AN ANALYSIS

Low-load and flexible operation of coal-based thermal power plants has direct and indirect implications for electricity tariffs through both variable and fixed cost components. As our analysis illustrates, flexibilisation affects energy charge rates, capacity charge recovery, and overall tariff structures.

On the variable cost side, efficiency degradation and increased auxiliary fuel consumption constitute the primary drivers of tariff escalation. As discussed earlier, net heat rate deterioration at lower loading levels leads to higher coal consumption per unit of electricity generated, increasing fuel costs reflected in the ECR. Similarly, increased secondary oil consumption due to higher Equivalent Forced Outage Rates (EFOR) and low-load combustion stability requirements further raises variable costs. CEA's analytical estimates indicate that oil-related variable cost impacts alone could increase ECR from 2.5 paisa/kWh under base-load norms to 3.5–5.0 paisa/kWh under flexible operation, depending on specific oil consumption levels.

Beyond variable costs, flexible operation affects fixed cost recovery through reduced plant load factors (PLFs), increased maintenance downtime, and higher forced outage rates. Cycling operation accelerates component wear and increases maintenance requirements, leading to reduced availability and making it more difficult for generators to recover full capacity charges under existing tariff frameworks. As plants operate at lower average load levels to provide system flexibility, fixed costs are spread over fewer units of electricity generated, effectively increasing the per-unit fixed cost component of tariffs.

Furthermore, flexibilisation-related capital expenditures and increased O&M costs will need to be recognised in tariff determination mechanisms to maintain the financial viability of thermal generators. These analytical findings highlight that flexible operation is not cost-neutral and that tariff frameworks must account for both variable efficiency penalties and fixed cost recovery challenges associated with low-load operation.

Overall, the tariff impact of flexibilisation reflects a systemic trade-off between integrating higher shares of variable renewable energy and maintaining reliable thermal backup capacity, underscoring the need for regulatory cost allocation mechanisms to internalise flexibility-related system integration costs. However, the greater share of RE into the power mix will reduce the overall operational cost of electricity, thereby the cost of flexible coal will be offset by the high RE penetration scenario going ahead.

ten years of historical cost data (2017 for NTPC and 2018 for GSECL). The study estimated normative O&M costs of **Rs 28.7 lakh/MW for 210 MW units and Rs 19.22 lakh/MW for 500 MW units**, which served as the baseline for estimating incremental cycling costs.

The study quantified incremental O&M impacts per operational event as a percentage of normative O&M costs. For **200 MW units**, cold starts increased O&M costs by **1.59 per cent per event at NTPC and 0.73 per cent at GSECL**, while warm starts and hot starts increased costs by **0.90 per cent and 0.66 per cent**, respectively.

For **500 MW units**, cold starts resulted in **2.73 per cent additional O&M costs per event at NTPC and 1.78 per cent at GSECL**, with warm and hot starts contributing **1.58 per cent and 1.28 per cent**, respectively. Significant load-following events had relatively minor impacts (0.01–0.03 per cent per event). These estimates highlight that start–stop cycling events, rather than ramping alone, are the dominant driver of damage-related costs.

Engie Lab’s international benchmarking estimated that annual capital and maintenance expenditures due to cycling could result in a **0.3–4.3 per cent increase in total unit costs**, equivalent to **Rs 0.01–0.15 per kWh**, depending on the frequency and depth of cycling events. These estimates were based on current levels of flexibilisation, where units operate at 55 per cent load or above with limited load-following, indicating that deeper flexibility requirements could further increase damage-related costs.

These findings indicate that cycling-related damage costs are a structural consequence of thermal flexibility and represent a key hidden cost of renewable integration that must be internalised within regulatory cost-recovery frameworks. Overall, damage costs represent long-term asset degradation and reliability impacts of flexibilisation. These costs are event-driven and plant-specific, influenced by coal quality, unit age, operational practices, and design characteristics. This underscores the need for regulatory frameworks to recognise cycling-induced life consumption and maintenance costs in tariff recovery mechanisms.

Additional Oil Consumption Costs

Flexible operation of coal-based thermal power plants can increase secondary oil consumption due to higher Equivalent Forced Outage Rates (EFOR), ageing-related degradation, and stability requirements at low-load operation. Secondary oil is typically used for flame stabilisation, start-up support, and combustion

stability during low-load or cycling conditions, and increased reliance on oil represents an additional variable cost component of flexibilisation.

Studies conducted by the Electric Power Research Institute (EPRI) along with NTPC Ltd., on the basis of global operational data, indicated that EFOR increases under variable operating regimes and with ageing of thermal units. Based on these findings, the CEA Roadmap suggests that existing CERC norms for specific oil consumption—0.5 ml/kWh under base-load operation (2014–19 norms)—will have to be revised upward for flexible operation.

NTPC assessments indicate that specific oil consumption could increase to 0.7 ml/kWh during load-following operations (<60 per cent load), 0.72 ml/kWh at 40–50 per cent minimum load, and 0.8 ml/kWh or higher at 30–40 per cent load, with allowances up to 1.0 ml/kWh under varying coal quality conditions. These estimates reflect the technical need for additional secondary oil to ensure safe and reliable combustion under variable load regimes, particularly in the Indian context of heterogeneous coal quality.

The subsequent assessment after additional oil consumption is the impact on variable tariff or the energy charge rate. Assuming an oil price of Rs 45,000 per kilolitre, the CEA Roadmap estimated that increased oil consumption would raise the energy charge rate (ECR) from 2.5 paisa/kWh under existing norms to 3.5–5 paisa/kWh, depending on specific oil consumption levels.

4.2 CERC Tariff Regulations for Flexibilisation

The Central Electricity Regulatory Commission (CERC), established under the Electricity Act, 2003, plays a central role in setting tariff frameworks for inter-state generating stations and transmission systems in India.

In India, the CERC—in the exercise of the powers vested in it under Section 178 of the Electricity Act, 2003 (36 of 2003), read with Section 61—determines the electricity tariff for the interstate operations, the latest one being for the period 2024 to 2029. The State Electricity Regulatory Commissions (SERCs) determine the electricity tariff for the intra-state operations, with CERC acting in an advisory role, as POWER falls under Entry 38 of the Concurrent List (List III) in the Seventh Schedule of the Indian Constitution.

Exercising its statutory mandate under Sections 61 and 178 of the Act, CERC notified the *Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024*, which came into force on 1 April 2024 and, unless

reviewed or extended earlier, remain applicable for the tariff period from 1 April 2024 to 31 March 2029.

A key regulatory shift under these regulations is the explicit recognition of expenditures required to enable flexible operation of thermal generating stations. Chapter 7 on computation of capital cost includes provisions that allow expenditure incurred or projected for enabling lower-load and flexible operation to be admitted as part of capital cost for tariff determination. Specifically, Regulation 19(2)(p) allows capital expenditure for enabling flexible operation for new projects, while Regulation 19(3)(g) extends this allowance to existing projects, subject to prudence checks by the Commission.

These provisions institutionalise flexibilisation as a legitimate cost category within the regulated tariff framework, signalling regulatory acknowledgement that retrofitting coal plants for variable renewable energy integration requires additional capital investments that must be recoverable through capacity charges. This marks a transition from pilot-driven policy discourse on flexibility to formal tariff recognition and cost recovery under India's statutory electricity regulatory architecture.

Need for Tariff Policy and its Evolution

Traditionally, coal-based capacity was contracted as baseload capacity because it was dispatchable and allowed utilities to schedule operations in a consistent and predictable manner. In order to meet its elevated ambitious goal, India requires greater flexibilisation of coal-based power plants to accommodate variable renewable generation.

The Central Electricity Regulatory Commission (CERC) notified the *Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019*, but these did not adequately address flexibilisation under low plant load factor (PLF) conditions. The CEA subsequently notified the *Central Electricity Authority (Flexible Operation of Coal-based Thermal Power Generating Units) Regulations, 2022* on **25 January 2023**, which initiated regulatory recognition of flexible operation. This recognition was formally incorporated into tariff frameworks through the *Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024*.

However, the 2024 tariff regulations did not specify detailed technical and operational compensation mechanisms, which were later introduced through the *National Load Despatch Centre (Mechanism to Work Out the Compensation*

Due to Part-Load Operation and Multiple Start/Stop of Units of the Generating Stations) Procedure, 2025.

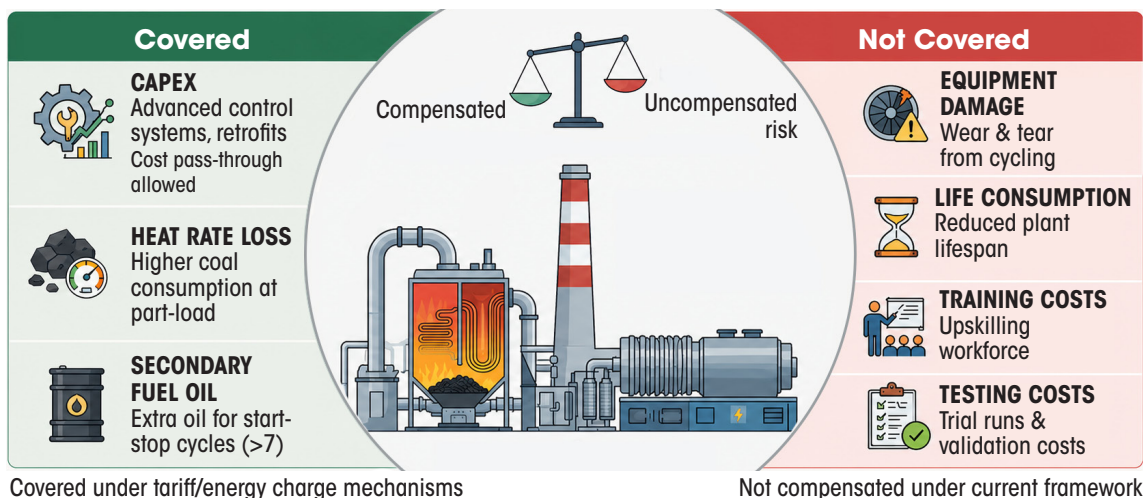
Recognition of Flexibilisation Elemental Costs

While the *Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024* marked an important step by allowing capital expenditure for enabling flexible operation, the regulatory framework initially focused primarily on upfront capital cost recognition. As discussed earlier in this chapter, flexibilisation imposes a broader set of economic impacts, including degradation of heat rate, increased auxiliary consumption, additional secondary fuel oil use, accelerated asset life consumption, and reduced capacity factor affecting fixed cost recovery. These operational and efficiency-related cost elements were not comprehensively addressed in the generic tariff framework notified in 2024, creating uncertainty regarding cost recovery for generators operating under system-driven flexibility mandates.

Recognising this regulatory gap, the CERC issued a subsequent clarification framework through its *Order on Procedure for Mechanism of Compensation for Degradation of Station Heat Rate, Auxiliary Energy Consumption and Secondary Fuel Oil Consumption due to Part-load Operation and Multiple Start/Stop of Units* on **14 July 2025**.

Figure 3: CERC Part-Load Tariff Mechanism

Current tariff design supports capital and limited operational costs, but leaves critical flexibility risks unaddressed



Source: CERC Regulation dated 14 July 2025

This framework was issued under Regulation 70(G)(10) of the Tariff Regulations, 2024, as amended by the *Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (First Amendment) Regulations, 2025*, which were notified on **4 February 2025**. The Order entrusts the **National Load Despatch Centre (NLDC)** with preparing and implementing the procedure for compensation, with approval and oversight by the Commission.

The procedure applies to designated coal-, gas-, and lignite-based generating stations whose tariffs are determined by **CERC under Section 62 of the Electricity Act, 2003**, and requires dissemination and implementation by Regional Load Despatch Centres (RLDCs) and Regional Power Committees (RPCs). The framework operationalises compensation for degradation in station heat rate, auxiliary energy consumption, and secondary fuel oil consumption attributable to part-load operation and multiple start-stop events, thereby extending regulatory recognition beyond capital expenditure to operational flexibility costs.

Elemental Coverage under the New Tariff Framework

The CERC has introduced a dedicated compensation framework to address the operational and efficiency-related costs of flexible thermal power generation. The framework operationalises cost recovery for flexibility-induced performance degradation in generating stations regulated under Section 62 of the Electricity Act, 2003. Under this segment we look at the various elements as highlighted above being covered by the tariff regulations.

Capital Expenditure (CAPEX)

Under the Tariff Regulations, 2024, capital expenditure incurred to enable flexible operations—such as control system upgrades, monitoring systems, and automation—are admissible as part of capital cost for tariff determination. This ensures that retrofit investments required to enable low-load and cycling operation can be recovered through capacity charges.

Operational Expenditure (OPEX)

The compensation framework addresses recurring operational costs associated with flexible operation, particularly increased fuel consumption and auxiliary power use. It provides a mechanism to calculate compensation for degraded station heat rate (SHR) and auxiliary energy consumption (AEC) when units operate at part load or undergo multiple start-stop events.

Heat Rate Degradation and Efficiency Losses

The procedure calculates compensation as the difference between energy charge rates under degraded and normative performance parameters. For example, if

a plant operating at lower load experiences higher coal consumption per unit of electricity, the resulting increase in energy charge rate is compensated through a defined formula based on average unit loading and scheduled generation.

Additional Secondary Fuel Oil Consumption

The framework explicitly compensates additional secondary fuel oil consumption caused by frequent start-ups and low-load operation. For instance, compensation is payable when annual start-ups exceed normative thresholds, with oil consumption costs calculated using weighted average landed fuel prices.

Cost Allocation and Billing Mechanism

Compensation is allocated among beneficiaries based on their contribution to low-load operations, including system scheduling and renewable integration-driven dispatch. Monthly compensation statements are issued by RPCs, with adjustments and reconciliation carried out annually.

Overall, the tariff framework moves beyond generic capital cost recognition to provide structured compensation for operational efficiency losses, auxiliary consumption, and oil usage arising from system-driven flexibility requirements, marking a significant step towards institutionalising flexibility costs within India's regulatory tariff architecture. The calculation mechanism is elaborated in detail in the next segment.

Calculation of Compensation under the Tariff Framework

The CERC compensation framework for part-load operation and multiple start-stop events operationalises flexibility cost recovery through formula-based adjustments to the Energy Charge Rate (ECR), using deviations in Station Heat Rate (SHR), Auxiliary Energy Consumption (AEC), and secondary fuel oil consumption. Compensation is calculated monthly on a cumulative basis and reconciled annually.

Heat Rate Degradation and Auxiliary Consumption Compensation

For each generating station, the framework computes two energy charge rates:

- i. Energy Charge Rate based on Scheduled Energy [ECR(SE)]
- ii. It represents the energy charge rate calculated using degraded Station Heat Rate (SHR) and Auxiliary Energy Consumption (AEC) at the average actual unit loading, i.e., based on the scheduled generation dispatched by the system operator.

- iii. Therefore, based on degraded SHR and AEC at the average unit loading (actual scheduled generation), and
- iv. Energy Charge Rate based on Declared Capacity [ECR(DC)],

It represents the energy charge rate calculated using degraded SHR and AEC at the declared capacity level, i.e., the capacity that the generator has declared as available for dispatch. Therefore, based on degraded parameters at the declared capacity.

Compensation is calculated as the difference between these two rates:

$$\text{ECR}_{\text{Comp}} / \text{Compensation Energy Charge Rate} = \text{ECR}(\text{SE}) - \text{ECR}(\text{DC})$$

Monthly compensation payable equals the effective scheduled generation multiplied by this ECR difference based on the monthly filings made by the unit under 19 parameters sought under the Annexure of the compensation rules. For example, if degraded operation increases ECR by Rs 0.10/kWh and the unit supplies 1,000 million kWh in a month, compensation would be Rs 100 crore for that period.

Final Compensation and Sharing Rules

Total energy charges based on actual parameters (EC(A)) are compared with normative energy charges (EC(N)) plus provisional compensation. If actual charges are lower, gains are shared 50:50 between generators and beneficiaries; if higher, the generator retains full compensation. This ensures risk-sharing while preventing over-recovery.

Secondary Fuel Oil Compensation

Additional secondary fuel oil consumption is compensated when annual start-ups exceed seven per year. Compensation is calculated as additional oil consumption per start-up multiplied by the number of attributable start-ups and the weighted average landed oil price.

For example, if additional oil use is 10 kilolitres per start-up, oil price is Rs 45,000/kL, and 20 start-ups occur, compensation equals Rs 9 crore annually.

Allocation of Costs Across Beneficiaries

Compensation is allocated to beneficiaries based on their contribution to low-load operation, measured through un-requisitioned energy below normative availability. Entities causing reduced requisition or system-driven flexibility (including SCED and SCUC schedules) bear proportional costs. Monthly billing is issued by generating stations and reconciled by RPCs.

Table 7: CERC's Part-Load Operation Tariff Mechanism

Operational Element	Coverage under Compensation Rules	Compensation Mechanism	Illustrative Example
CAPEX	Yes	Cost pass through under Grid Code	Cost of installing advanced control systems or modifying boilers/turbines to enable flexible operation.
OPEX	Limited coverage	Governing Tariff Compensation Rules of a TPP	Additional staffing, maintenance, and operational effort required for frequent ramping not fully compensated.
Heat Rate Degradation and Efficiency Losses - OPEX	Yes	Based on calculated energy charge under Tariff Compensation Rules of a TPP	Higher coal consumption per unit when operating at part-load.
Additional Secondary Fuel Oil Consumption - OPEX	Yes – Beyond 7 start/stops	Governing Tariff Compensation Rules of a TPP	Extra fuel oil used during frequent start-ups and shutdowns beyond 7 cycles.
Equipment Damage Cost	No	--	Increased wear and tear on boiler tubes, turbines, and auxiliaries due to frequent cycling.
Life Consumption cost	No	--	Reduction in plant lifespan due to thermal stress and repeated ramping operations.
Training/Upskilling Cost	No	--	Training plant operators to manage flexible operations and advanced control systems.
Testing Schedule Generation Cost	No	--	Costs incurred during trial runs and testing to validate flexible operation protocols.

Source: CERC Regulation dated 14 July 2025

Overall, the framework translates technical flexibility impacts into formula-driven tariff adjustments, providing plant operators with predictable recovery of efficiency degradation and fuel-related costs while embedding flexibility economics into India's regulated tariff regime. For clarity on the elemental coverage and the computation of the same, refer to the table below (see *Table 7: CERC's Part-Load Operation Tariff Mechanism*).

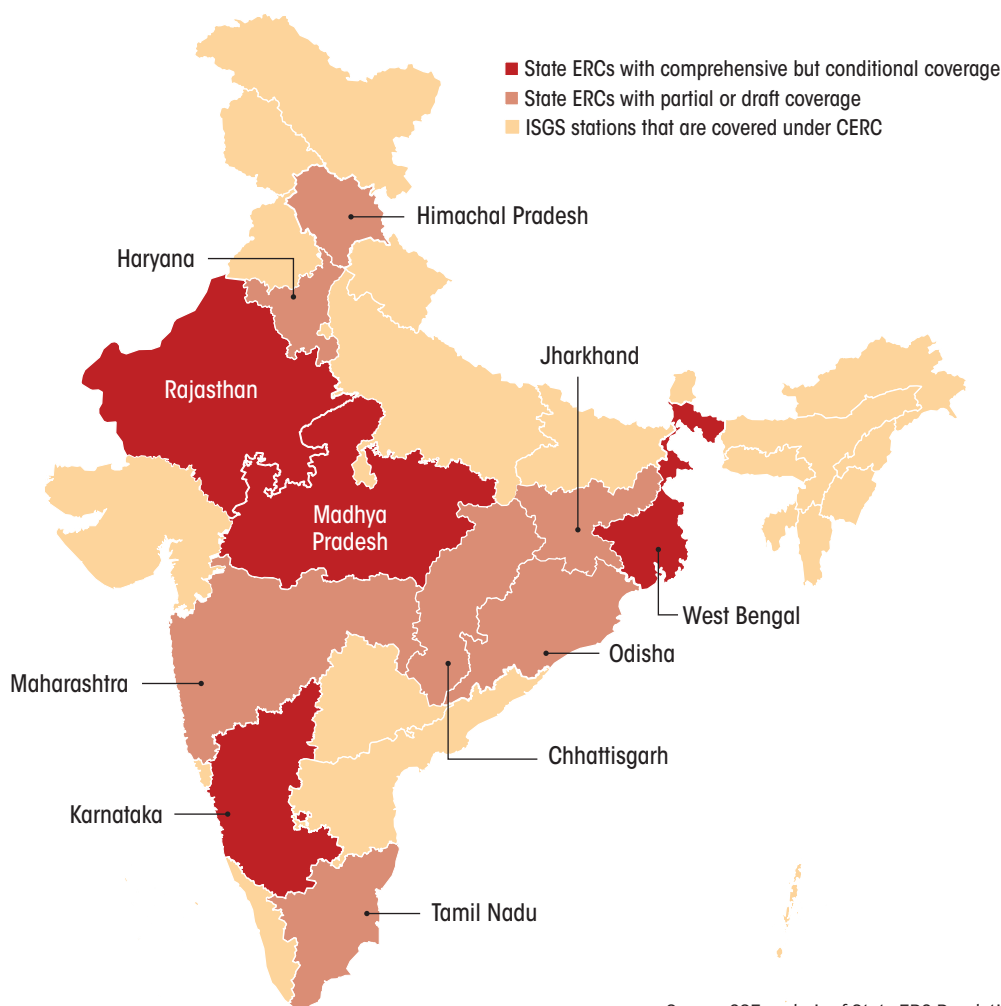
4.3 State ERCs Regulations for Flexibilisation

Indian electricity governance architecture stipulates that thermal units owned by respective states or supplying power exclusively to the state are independently governed by their states' Electricity Regulatory Commissions (ERCs). The Flexibilisation architecture is therefore governed by the ERCs across two parallel streams, the CAPEX for technical retrofits and the Operational Tariff for day-to-day operations. These are thus governed by two segments of regulations, the Tariff Regulations and the Grid Code of each ERC.

By default, all ERCs recognise 55 per cent as the MTL of their thermal units, and therefore lower load operations become an exception rather than the norm. As

Map 1: Regulatory Coverage of Thermal Flexibility Compensation in India

Current tariff design supports capital and limited operational costs



Source: CSE analysis of State ERC Regulations

of July 2026, CSE analysis of the ERC regulations has estimated the coverage of both streams, i.e. CAPEX and Operational Tariff. The estimation has divided the coverage into three categories of coverage, *Comprehensive but Conditional*, *Partial or Draft* and *No Regulatory*. States that have mentioned Flexible Operations or Part Load Operations in their regulations but have not actually taken policy steps for their implementation have been categorised as absent. The analysis excludes the state of Andhra Pradesh as its database has not been accessible.

The CAPEX requirement has to be mentioned within the Tariff Regulation by the ERCs. This can then be directly mandated or allowed on a case-by-case basis. The former method is better as it allows each thermal unit to begin work on its

unit to accommodate the retrofits without waiting for the ERC approval. For the Operational Tariff, the GRID Code has to mention the operating parameters and the payout mechanism. Without this, a technically capable unit will not operate at lower loads, as it will not be paid for such operations.

Comprehensive but Conditional Coverage

The category of comprehensive but conditional is so defined because the ERC regulations in this category are aligned with the central rules formulated by CEA and CERC but do not cover the operational coverage identified by CSE's analysis.

Four Indian states, namely, West Bengal, Karnataka, Rajasthan and Madhya Pradesh, have introduced compensation mechanisms to both aspects of flexible operations, i.e. CAPEX and operational tariff. Yet, all require case-by-case basis approval for flexible operations, meaning respective thermal units have to approach ERC before undertaking retrofits. Rajasthan's Suratgarh (SSC) TPP Unit-8 has filed a petition on these lines for technical retrofit approval before RERC in April 2026. On Tariff payout, Karnataka and West Bengal have listed the mechanism as per CERC's method but have mentioned that the SLDC will come up with a mechanism at a later date. Rajasthan's GRID code is yet to finalise its tariff mechanism in full, as they have not yet approved any technical retrofits.

Partial or Draft Coverage

Three Indian states, namely, Jharkhand, Tamil Nadu and Odisha, have provided partial coverage of a greater degree for flexible operations. These states have some policies for flexible operations in motion. Tamil Nadu is more advanced than the other two in its progress, as it already provides CAPEX payout for retrofit and its tariff mechanism, in line with the CERC mechanism, is in the draft stage. Jharkhand's tariff mechanism is in draft stage and is similar to the CERC method but has been independently mentioned for clarity purposes. Odisha provides CAPEX for retrofits on a case-by-case basis, but the tariff coverage is missing.

A notch behind with regulatory mention but without amendment steps are Maharashtra, Haryana, Chhattisgarh, and Himachal Pradesh. Himachal Pradesh's Regulation states that the MTL requirement is to be aligned with the CEA Regulations 2023, but cost and operational tariff coverage are not specified. Chhattisgarh and Maharashtra have stated that Grid Code regulations will determine tariff, yet no amendment has been notified or is in draft stage as per public information. Haryana's regulations mention emission tracking from part-load operations but have not notified any amendment to enable the CEA Flexible Operation Regulations.

No Regulatory Coverage

Nine states, namely, Telangana, Uttarakhand, Uttar Pradesh, Punjab, Kerala, Gujarat, Delhi, Bihar and Assam, are yet to take any regulatory steps to align their laws to enable flexible operations. Among these, Assam, Bihar, Delhi, Kerala and Uttarakhand do not directly own any thermal units that are part of the CEA's phasing plan, yet do receive power from thermal units and determine the tariff framework for their power supply.

In conclusion, India's flexibilization compensation regime remains fragmented across jurisdictions, with varying coverage and different methodologies. The partial regulatory coverage disadvantages TPPs pushing for compliance with lower operations. Similarly, the default nomenclature of 55 per cent MTL lacks inertia to push TPPs towards complying with CEA's phasing plan, as the case-by-case basis creates a time gap and does not create an automatic compliance requirement. Above all, the regulations do not cover the gaps in the operational tariff highlighted by CSE analysis.

4.4 Section 62 & 63 Differential

The current CERC tariff compensation framework for flexible operation applies only to generating stations whose tariffs are determined under **Section 62 of the Electricity Act, 2003**. These cost-plus units are eligible for compensation for efficiency degradation, auxiliary consumption, and secondary fuel oil use arising from part-load operation and multiple start-stop events. In contrast, generating stations operating under **Section 63**, where tariffs are discovered through competitive bidding and fixed under long-term power purchase agreements, do not receive regulatory compensation for flexibilisation-related costs automatically. This creates an asymmetric incentive structure, despite the CEA's flexible operation regulations and phased implementation plan applying uniformly across India's coal fleet, including both Section 62 and Section 63 units.

Therefore, while the regulatory framework has begun to recognise and partially compensate the costs of flexible operation, significant gaps remain in coverage, consistency, and equitable cost allocation across the thermal fleet. These gaps, underscore the need for a more harmonised and comprehensive compensation framework to support system-wide flexibilisation. Against this evolving regulatory backdrop, the critical question shifts from policy design to implementation, how these frameworks are being operationalised across the coal fleet, with the same being examined in the next chapter.

5

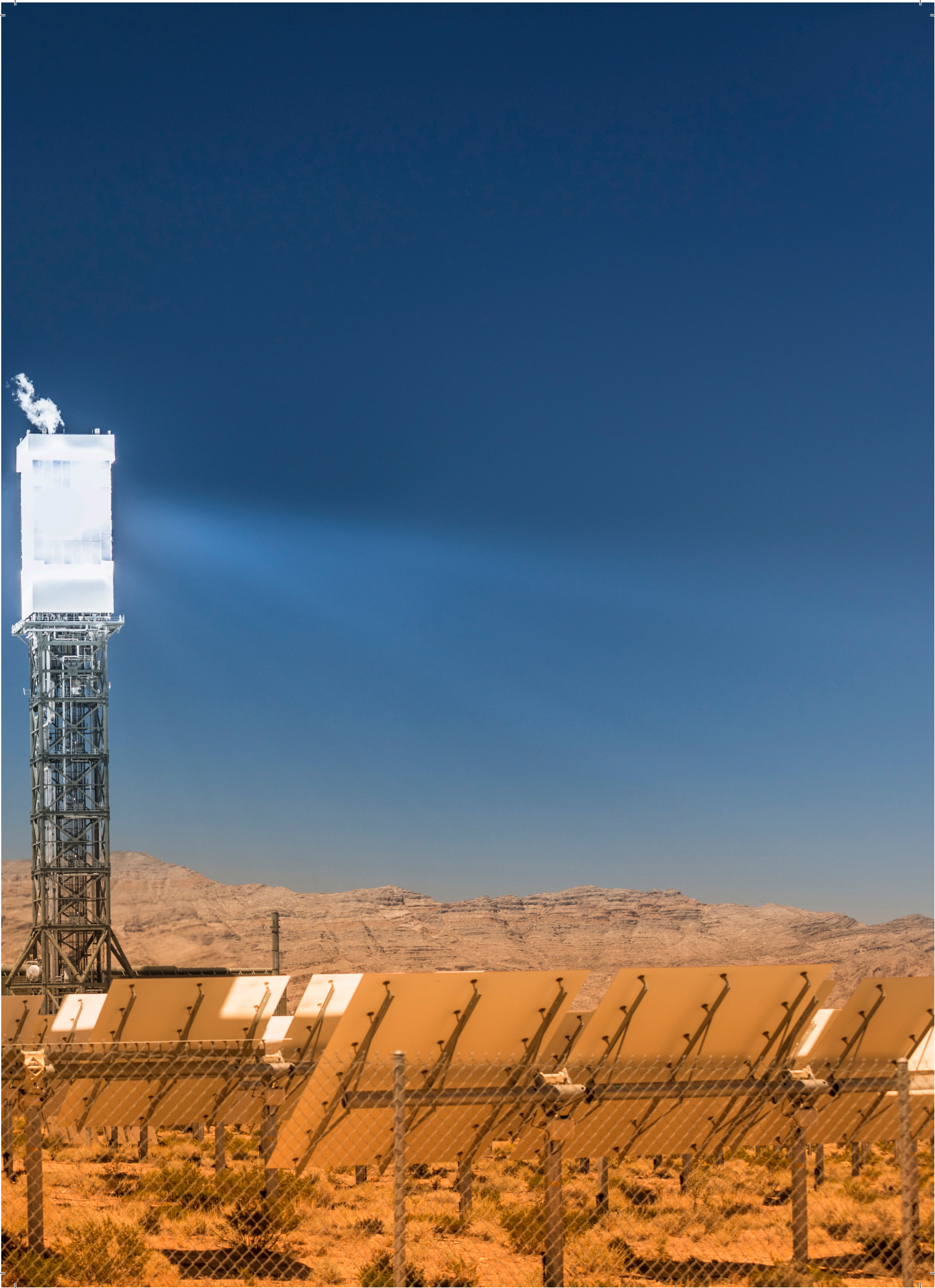
IMPLEMENTATION STATUS

The phasing plan is behind schedule, with the pilot phase incomplete and Phase 1, originally due by 2026, yet to begin

Against a target of 5.85 GW in pilot phase, just one unit (~500 MW) has fully demonstrated both low-load operation and ramping compliance

Only ~1.9 GW of capacity has demonstrated 40 per cent MTL capability, while ramping achievement limited despite technical feasibility established through pilot studies

AGC enables four-second real-time frequency correction, with 144 coal-based units comprising 72.3 GW under coverage aiding system stability





The CEA's Flexible Operation of Coal-based Thermal Power Generating Units Regulations, 2023, published in January 2023, created a legal obligation to achieve a 40 per cent MTL across all centrally, state-, and privately-owned coal-based thermal power plants in India. The regulations declared the CEA as the designated authority for implementation of these rules. In accordance of the same, the CEA brought in a "Phased Plan" divided into four phases for the implementation of the regulations across the fleet.

As per the phased plan released in 2023, a total of 493 units with a combined capacity of 196.7 GW are mandated to achieve the target threshold. The plan's timeline was to run from July 2024 until December 2030, with the pilot phase beginning May 2023 to December 2023. This pilot phase was slated to cover 10 units with a capacity of 5.85 GW. Subsequently, Phase 1 ought to be currently ongoing, with the original timeline of July 2024 to June 2026, encompassing 91 coal units with combined capacity of 51.08 GW. Currently, as of February 2026, India has a total of 227.8 GW of coal-based thermal power capacity, hence 31.1 GW of existing capacity is not covered in the plan.

Effective flexibility is essential for ensuring stable electricity supply while accommodating the nation's ambitious clean energy expansion goals. This chapter reviews the current implementation status of the plan and dives deeper into the criteria of the phased plan to examine how implementation is unfolding on the ground. *Firstly*, the status of the phased plan is reviewed, situating progress against the timelines laid down by the CEA. *Secondly*, the chapter presents an assessment of CEA-led test runs, analysing ownership-wise performance and actual technical achievements vis-à-vis prescribed targets based on the criteria's prescribed. *Thirdly*, the operationalisation of Automatic Generation Control (AGC) is analysed at the unit level, focusing on the rollout of four-second frequency control across coal units under GRID-India.

5.1 Current Status of Phasing Plan of Flexible operation

The CEA's phasing plan for the flexible operation of coal-based thermal power plants is structured around a set of technical, operational, and system-level considerations to enable a smooth, least-cost transition toward lower minimum technical loads. Key criteria include unit design characteristics, proximity to renewable energy-intensive states, fuel logistics, age and vintage of units, and inherent technological limitations such as boiler type and milling systems. Newer coal units with coordinated control systems and designed to operate without oil support above a 40 per cent load were prioritised, as these require minimal retrofits and can achieve flexibilisation primarily through control system tuning.

System needs also played a role, with greater emphasis placed on accommodating thermal units located in renewable-rich states to manage variability from high solar and wind penetration, while pithead stations and older subcritical units were deliberately deferred to later phases due to their lower operational efficiency and higher retrofit complexity.

Based on these criteria, the pilot phase of the phasing plan, **10 coal-based generating units across the central, state, and private sectors** were identified in a meeting held on **19 April 2023** for lowering the MTL to **40 per cent of rated capacity**. The pilot phase, was slated to be completed by December 2023. It involved test runs, refurbishment, and a subsequent performance evaluation period, with operational learnings intended to inform and de-risk implementation during Phase 1 of the flexibilisation programme.

Phase 1 of the implementation plan covers the period from July 2024 to March 2026 and primarily includes coal units commissioned between January 2016 and December 2022. Select units commissioned before 2016 have also been included where they are located in renewable-intensive states and deemed suitable for early flexibilisation, while some newer units in low-RE states have been shifted to subsequent phases. A two-year timeline was provided to reflect the estimated duration required for control system tuning, testing, and stabilisation of operations at 40 per cent minimum technical load.

The CEA's *Thermal Projects Renovation & Modernisation Division (TPRM)* is the monitoring body for the plan that provides details on the implementation of the plan via its quarterly reports. As mentioned above, the original Phase 1 plan targeted to retrofit 91 coal units comprising a combined capacity of 51.08 GW, 22.4 per cent of the total coal fleet planned for retrofits.

Parameters for Implementation Valuation

The implementation of the flexible operation framework is to be tested against the mandatory technical and operational criteria laid down in the CEA Regulations, 2023. At the core of compliance is the ability of coal-based thermal power generating units to operate flexibly with an **MTL of 40 per cent**, with interim thresholds of 55 per cent to be achieved within one year for units currently operating above this level. Simultaneously, the regulations require units to demonstrate specified **ramp rate capabilities**, which include 3 per cent per minute between 70–100 per cent load, 2 per cent per minute between 55–70 per cent load, and 1 per cent per minute between 40–55 per cent load, in line with the phasing plan notified by the Authority. Load Despatch Centres are mandated to schedule units in accordance

with these declared flexibility capabilities, thereby embedding compliance within real-time grid operations. Progress under the phasing plan is therefore assessed not only by physical modifications and control system readiness, but also by demonstrated operational performance during scheduling and dispatch. Provision for regulatory relaxation on a case-by-case basis allows implementation challenges to be addressed without diluting the overall objective of system-wide flexibilisation.

Table 8: India's Flexible Operation Criteria for TPPs

Flexibilisation Criteria		
Minimum Technical Load	Interim MTL threshold	55 per cent, units unable to reach 55% MTL to achieve it within one year of notification
	Target MTL threshold	40 per cent
Ramp Rate	High load range (70–100 per cent MTL)	≥3% per minute
	Mid load range (55–70 per cent MTL)	≥2% per minute
	Low load range (40–55 per cent MTL)	≥1% per minute

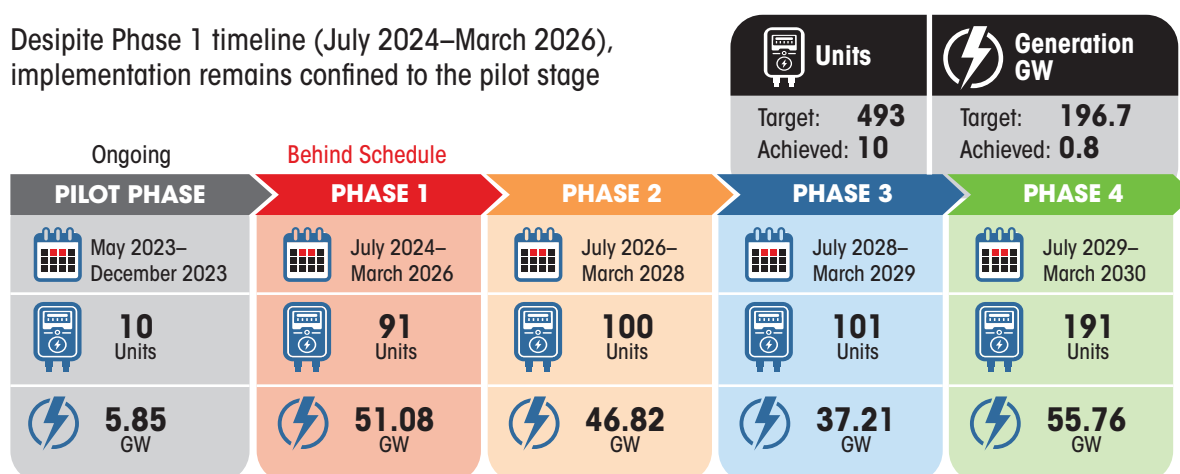
Source: CEA's Flexible Operation of Coal-based Thermal Power Generating Units Regulations, 2023 – January 2023

Progress of Phasing Plan Implementation

As per the latest available quarterly report from the CEA's TPRM division, the scale of achievement under the regulations has been varied. The coal fleet has majorly achieved the 55 per cent MTL threshold, with 202.4 GW of capacity to have achieved this parameter. Notably, this threshold does not require any retrofit in a coal unit.

Figure 4: India: Flexibilisation Phasing Plan

Despite Phase 1 timeline (July 2024–March 2026), implementation remains confined to the pilot stage



Source: CSE analysis of CEA Phasing Plan, 2023

Recognising the delay in the implementation of the phasing plan, the quarterly report states that only 10 units, totalling 5850 MW under the pilot phase, are at different stages of execution of the pilot phase. This indicates that even the pilot phase of the phasing plan has not been completed yet.

Review of Phasing Plan: Assessment and Observations

Implementation experience to date indicates **uneven progress across utilities**, reflecting differences in unit vintage, contractual arrangements, and retrofit readiness rather than a uniform technical constraint. Among central sector units, **NTPC's Mauda TPS Unit-1 (500 MW)** has demonstrated operation at a 40 per cent MTL under controlled conditions, though its ramp-rate capability remains constrained at 2 per cent per minute; while, **Simhadri Unit-3** and **Dadri Unit-6** are still under evaluation. **DVC's Mejia TPS Unit-8 (500 MW)** stands out as an early success, having achieved both the 40 per cent MTL and the prescribed ramp rates by December 2024, thereby illustrating the feasibility of full compliance where retrofit and testing pathways are clearly defined.

In contrast, several state-sector units remain at intermediate stages, highlighting institutional and procurement-related bottlenecks. **Neyveli New TPP Unit-2 (500 MW)** has yet to enter the execution phase, with tenders still under evaluation. Meanwhile, **KPCL's Yeramarus TPS Unit-1 (800 MW)** has completed performance guarantee testing but continues to stabilise low-load operations through extended data capture. **GSECL's Wanakbori TPS Unit-6 (800 MW)** has achieved the 40 per cent load threshold, but its ramp-rate compliance is pending OEM inputs, underscoring the dependence on vendor engagement. At **RRVUNL's Suratgarh SCTPP Unit-8 (660 MW)**, delays arising from boiler issues and ambiguities in contract scope slowed progress, though successful re-testing in February 2025 indicates a gradual resolution. **WBPDC's Sagardighi TPS Unit-3 (500 MW)** has met the MTL requirement, while the absence of a confirmed status for **APL's Raigarh TPS Unit-1 (600 MW)** suggests reporting or implementation gaps that warrant closer monitoring.

Therefore, from the reported data, the targeted parameters for flexibilisation have been completely achieved by only **one unit, i.e. DVC Mejia Unit-8 (500 MW)**. Three more units have achieved the 40 per cent MTL status, taking the total capacity of fleet capable of low MTL to 1960 MW/1.9GW. However, these units are yet to demonstrate ramp rate capability.

Table 9: Status on CEA's Flexibilisation Phasing Plan: Achievement Across Various TPPs

Utility/Unit	Capacity (MW)	40% MTL Status	Ramp Rate Status	Key Insight/Constraint
NTPC – Mauda TPS U-1	500	Tested in controlled operation	Limited to 2%/min	Demonstrates technical feasibility; ramp-rate upgrade pending
NTPC – Simhadri U-3	500	Under assessment	Under assessment	Evaluation phase ongoing
NTPC – Dadri U-6	490	Under assessment	Under assessment	Yet to demonstrate compliance
DVC – Mejia TPS U-8	500	Achieved	Achieved	Early full compliance; benchmark case
NLC – Neyveli New TPP U-2	500	Not achieved	Not applicable	Tendering and procurement stage
KPCL – Yeramarus TPS U-1	800	PG test completed	Stabilisation ongoing	Data capture underway for sustained low-load operation
GSECL – Wanakbori TPS U-6	800	Achieved	Pending	Dependent on OEM technical and budgetary inputs
RRVUNL – Suratgarh SCTPP U-8	660	Achieved (re-test Feb 2025)	Under resolution	Delays due to boiler issues and contract scope
WBPDC – Sagardighi TPS U-3	500	Achieved	Not specified	MTL achieved; ramp data not reported
APL – Raigarh TPS U-1	600	Not reported	Not reported	Status unclear; monitoring required

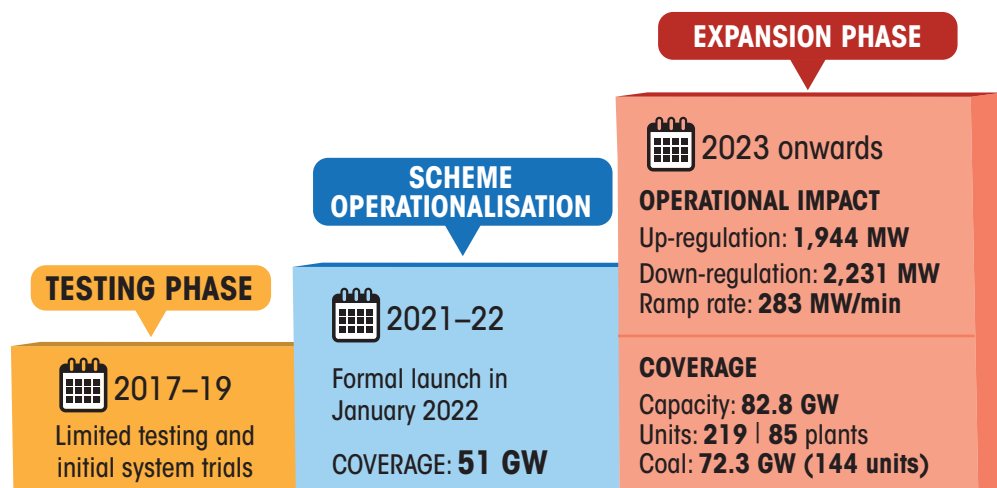
Source: CEA's Quarterly Review Report Renovation & Modernisation of Thermal Power Stations, September 2025

AUTOMATIC GENERATION CONTROL SYSTEM

Parallel to plant-level flexibilisation efforts, the operationalisation of Automatic Generation Control (AGC) under GRID-India has emerged as a critical system-level intervention to manage real-time imbalances in the power system. Traditionally, grid balancing in India relied on manual or semi-automated interventions by system operators, supported by primary response from generators.

With rising penetration of variable renewable energy (VRE) and the inherent inflexibility of coal-based generation, India's power system is transitioning away from a traditional base-load paradigm towards a real-time balancing framework. Earlier, thermal plants operated as steady base-load providers with limited need for rapid adjustments. However, with solar generation concentrated during midday and sharp evening demand peaks, the system now requires continuous, dynamic balancing of supply and demand. In this context, it is necessary to rely on system-level mechanisms that can respond quickly to real-time grid conditions.

AGC enables real-time balancing of power supply and demand by sending automatic signals to generators every four seconds, which helps maintain grid frequency and system reliability. This capability is critical to scale-up variable renewable energy sources, like solar and wind, which fluctuate throughout the day. By enhancing the grid's ability to respond quickly to these changes, AGC supports the integration of renewables and aids in making coal and other conventional generation more flexible in operation. AGC is being operated by Power System Operation Corporation (POSOCO) through the NLDC. Following pilot operations during 2017–19, AGC was operationalised at scale from July 2021 and formally inaugurated in January 2022, at which stage it covered around 51 GW across 50 generating stations.

Figure 5: Evolution and Scale-Up of AGC in India

Source: Status Highlight of SRAS/AGC, GRID India

Implemented through the Secondary Reserve Ancillary Services (SRAS) framework, AGC enables generating units to respond automatically to frequency deviations, providing a continuous balancing layer between primary response and tertiary interventions. Since its formal launch, the system has expanded steadily across regions and ownership categories, and as of December 2025, 85 power plants comprising 219 units with an installed capacity of 82.8 GW are operating in continuous AGC mode. This rapid scale-up underscores AGC's role as a system-level flexibility instrument complementing the slower, unit-level rollout of coal plant flexibilisation.

Coal-based stations dominate participation in AGC, accounting for 72.3 GW across 144 units, underscoring the central role of thermal generation in providing fast, dispatchable flexibility to the grid. Integration spans all regions, with the largest capacities in the Western and Southern regions, while 6.8 GW of intra-state capacity has also been brought under regional SRAS, marking an important shift toward decentralised flexibility provision.

Operational performance indicators suggest that AGC is already delivering tangible system-level benefits. The system has enabled up-regulation of up to 1,944 MW and down-regulation of 2,231 MW, with an average contribution of around 595 MW and peak ramping capability reaching 283 MW per minute. Unlike the earlier system, where adjustments were largely made in 15-minute blocks, often requiring large, sudden changes in generation, AGC breaks this into much smaller, continuous corrections. In effect, instead of making one large adjustment, the system makes multiple smaller steps, reducing stress on generators and improving stability. For example, during a sudden drop in solar output or a spike in demand, AGC gradually ramps up generation across units in real time, rather than forcing a sharp increase at the next scheduling block. The step-by-step response helps maintain frequency more effectively while easing operational strain on the system.

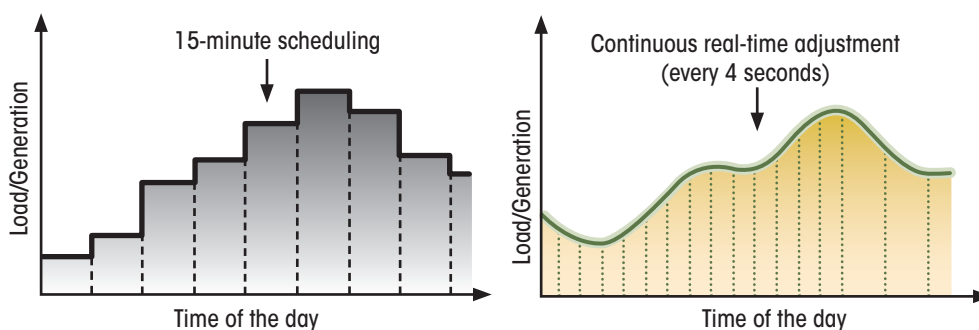
From an institutional perspective, AGC participation has expanded beyond central utilities to include state utilities and independent power producers. Notably, MPL (2×525 MW) became the first IPP to be integrated under AGC in 2021, while Khurja (2×660 MW) in Uttar Pradesh was inducted as the first intra-state generating station in July 2025. The accompanying commercial framework,

featuring weekly settlement and performance-based incentives of up to Rs 0.50/kWh, has resulted in typical investment recovery periods of 6–12 months, with providers offering 50 MW reserves earning around Rs 5 crore annually in incentives. Collectively, these developments indicate that AGC is transitioning from a pilot grid-support mechanism to a scalable, economically viable instrument that complements plant-level flexibilisation.

Against the backdrop of rising renewable penetration and an existing 220 GW coal fleet, with a further 95 GW under construction, the scaling up of AGC–SRAS is critical to redefining coal's role from baseload supply to system balancing. AGC-enabled operation allows coal units to absorb renewable variability more efficiently, but with only about one-third of the coal fleet currently integrated, accelerating AGC readiness, especially for upcoming capacity, remains essential to avoid future flexibility gaps.

Figure 6: Explainer on AGC

Continuous and automatic, directly responding to frequency requirements. It showcases how the automated system reduces monitoring by the operator



Source: CSE analysis of GRID India documents + Google Nano Banana usage

6

INTERNATIONAL EXPERIENCES

China has retrofitted over 300 GW of coal capacity for flexibility, supported by strong policy mandates and capacity payment mechanism

Germany operates a market-driven flexibility framework with 15-minute dispatch intervals, enabling efficient integration of high renewable penetration

Chile has achieved a reduction in emissions while demonstrating flexibility aided through a market-based dispatch and clear policy timeline

International experience shows that clear market signals, compensation frameworks, and system planning are critical for scaling thermal flexibility in India



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6.1 China – Journey towards Thermal Flexibility: From Rigidity to Responsiveness

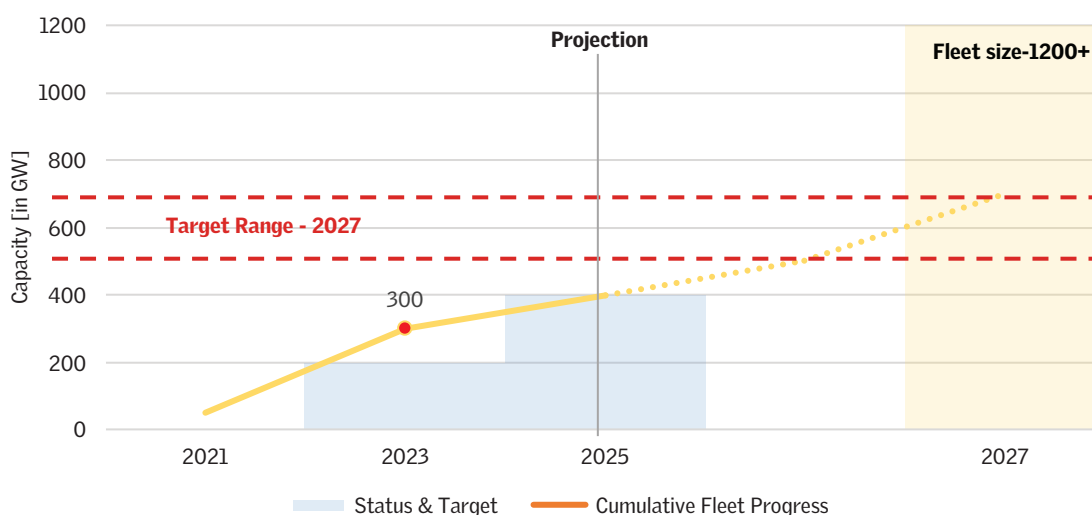
China's transition toward thermal power flexibility has been shaped by mounting system pressures arising from rapid renewable energy expansion and the need to maintain grid reliability. Commitments to operate coal units more flexibly have emerged against the backdrop of declining coal plant utilisation in a coal-dominated system that is undergoing a fundamental change in its operating logic. China's approach is characterised by strong state direction, incremental technical retrofits, and the use of administrative incentives embedded within dispatch practices and contracting frameworks to translate policy intent into operational outcomes.

China consumes the largest volume of coal globally, supported by an installed coal-fired power capacity of approximately 1,189 GW. While coal power emissions are estimated to peak around FY 2025–26, the role of coal plants is already shifting, from providers of inflexible baseload generation toward suppliers of **“peaker” and balancing energy**. Although the country has continued to add new coal capacity, the utilisation factor of the coal fleet has declined and is expected to fall further. New coal additions are driven less by aggregate power shortages and more by fragmented, province-level planning aimed at meeting local peak demand and energy security objectives, rather than by sustained growth in coal generation.

Against this backdrop, China has moved decisively to re-engineer the operational role of its existing coal fleet. The 14th Five-Year Plan (2021–2025) established an initial target to retrofit 200 GW of coal-fired capacity for flexible operation, covering approximately 16.8 per cent of the total fleet. The National Development and Reform Commission's (NDRC) Special Action on Upgrading New-Generation Coal Power (2025–2027) provided detailed technical parameters to drive implementation. Importantly, flexibility retrofitting has progressed more rapidly than originally envisaged. According to official assessments cited by the China Electric Power Planning & Engineering Institute, more than 300 GW of coal-fired units had already completed flexibility retrofits by the end of 2023, exceeding 14th Five-Year Plan targets ahead of schedule.

These upgrades have effectively released over 30 GW of additional system regulation capability, comparable to the contribution of large-scale energy storage, demonstrating both the technical feasibility and system value of coal flexibility at scale.

Graph 27: China's Coal Flexibility Retrofit Trajectory



Source: CSE analysis of Chinese policy documents

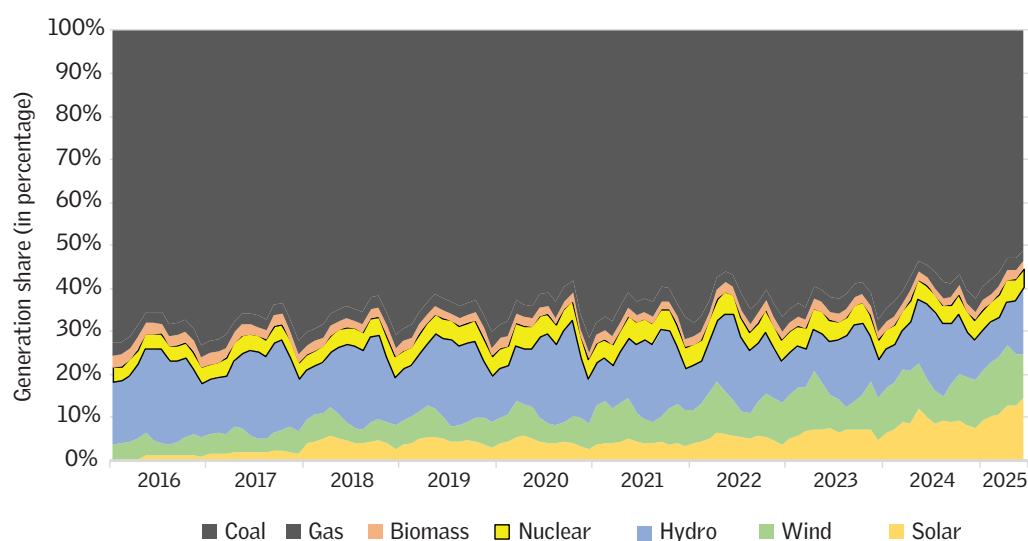
Looking ahead, policy ambition now extends beyond early gains toward comprehensive system coverage by 2027. The NDRC and the National Energy Administration (NEA) have articulated the objective of “**retrofitting all coal units that should be retrofitted**”, recognising that some units, such as those with special boiler configurations, heating obligations, or limited remaining lifetimes face practical constraints. Official estimates place the total pool of coal units requiring retrofit at **500–700 GW**, implying that an additional **200–400 GW** will need to be upgraded between 2024 and 2027, at an annual pace broadly consistent with achievements over the past three years.

As renewable capacity surpassed **1.5 TW** in 2023, accounting for nearly **52 per cent** of China’s total installed power capacity, the next phase of coal flexibility reform increasingly emphasises deeper peak-shaving, lower minimum stable loads, and tighter performance standards. The policy emphasis is shifting from volume to quality, in high-renewables regions, coal units are being pushed toward **deep peak-shaving**, with minimum stable loads below **30 per cent** of rated capacity. In this evolving context, coal flexibility is no longer framed as a transitional measure, but as a core enabler of reliability within China’s emerging “**new-type power system**.”

Chinese Power System: Under Transition

China’s power system transition is also shaped by the **New State Council Action Plan (2025-2027)**’s vision for building a “**new-type power system**”,

Graph 28: China: Power Generation Share by Sources



Source: CREA

which explicitly positions coal power as a supporting and safeguarding resource rather than a capacity slated for rapid withdrawal. Under this framework, coal is expected to continue playing a stabilising role during the transition period, even as renewable penetration accelerates and system flexibility requirements intensify.

Unlike India, resource planning for new coal plants in China is very provincial. Provincial administrators approve plants to ensure they meet their respective peak power demand without having to import power from another province. This leads to over building of capacity in respective provinces, as has happened previously in the 2010s and in other sectors of the nation. New coal may not necessarily mean greater emissions as the respective utilisation of units is falling.

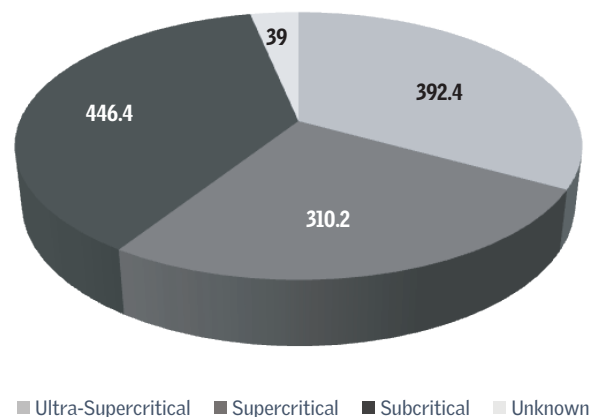
Coal's persistence in China is further explained by its **dual structural role** in the economy. Beyond electricity generation, coal remains critical for supplying energy to China's vast industrial base and for **combined heat-and-power (CHP) applications**, particularly in northern provinces where coal-fired plants provide district heating during severe winter conditions. These non-electricity obligations impose operational constraints on coal units and reinforce the need for a gradual, managed transition rather than abrupt capacity displacement. Recognising the financial scale of this transition, the National Development and Reform Commission (NDRC) has anchored its strategy in cost-controlled, incremental

retrofits, prioritising technical upgrades that enhance flexibility without requiring wholesale plant replacement, thereby aligning national energy objectives with fiscal and operational pragmatism.

Yet, new coal is being built in a hurry as 2027 is seen as the deadline for new coal-based capacity addition, leading to flurry of approvals and capacity additions. The country added approximately 49 GW of coal-fired capacity in 2023 and a further 30 GW in 2024. The first half of 2025 saw a 21 GW addition in capacity, the highest half yearly addition since 2016.

The Chinese coal-based thermal fleet is dominated by more advanced technology types, such as ultra-supercritical and supercritical configurations. The fleet comprises approximately 26 per cent supercritical units, 33 per cent ultra-supercritical units, and a legacy component of 37.5 per cent subcritical units. Based on capacity-weighted commissioning data from global coal fleet databases, China's operating coal power fleet has an estimated average age of around 12–15 years, reflecting a relatively young stock shaped by large-scale capacity additions since the mid-2000s.

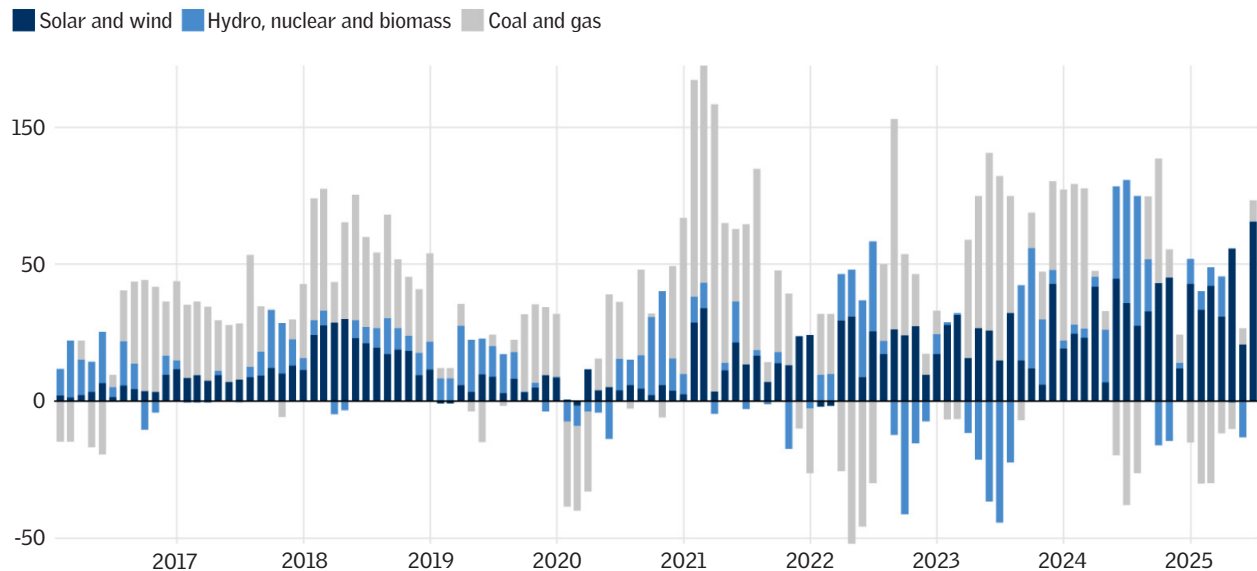
Graph 29: China's Coal Capacity: Technology-Split (in GW)



Source: Bloomberg Global Coal Countdown

Despite these additions, coal's share in the electricity generation mix for the country has continued to fall. Latest estimates show that the share has fallen from 73 per cent in 2016 to approximately 51 per cent by June 2025. With rapid addition of renewable energy, the trend is likely to continue. The country added 360 GW of combined solar and wind energy in 2024 and is on course to add more than 50 per cent of the world's solar and wind energy capacity installation in 2025.

Graph 30: China: Shrinking Share of Coal



Source: CREA

The 15th five-year plan (2026–30) is slated to bring in a renewed shift with “a comprehensive green transformation” among its intended goal.

System pressures are driving the shift in the operational nature of coal units across the country. In recent years, China has experienced rising renewable energy curtailment, officially reported at around 5 per cent, with indications that actual curtailment may be higher. Rather than reporting curtailment directly, Chinese system operators typically publish offtake rates, which have fallen from near 100 per cent historically to an average of around 95 per cent, reflecting growing system inflexibility amid rising variable generation. In line with the falling share of coal in the generation mix, operations for the coal plants ought to be more responsive and load-following role rather than as inflexible baseload assets.

New Regulations

China’s latest regulatory framework positions coal power firmly as a system-balancing resource, rather than a pure baseload technology. Under the 14th Five-Year Plan and reinforced through the *Implementation Plan for the Special Action on Upgrading New-Generation Coal Power (2025–2027)*, the country has set a target to retrofit up to 200 GW of its existing coal fleet for flexible operation, with the aim of delivering 30–40 GW of additional system regulation capacity within a two-year window. This distinction is critical; while a large share of the

fleet undergoes technical upgrades, only a subset translates into net, dispatchable flexibility at the system level. The regulatory emphasis is explicitly linked to facilitating renewable energy integration and strengthening grid reliability as China advances toward a “*new-type power system*.”

For existing coal-fired units, the regulations focus on incremental but wide-ranging retrofits under the “***Three Retrofits in Coordination***” framework, covering *efficiency, flexibility, and environmental performance*. Existing units are required to lower their minimum stable generation levels to 25–40 per cent of rated capacity, achieve ramp rates of 0.8–2.5 per cent per minute, and improve start-stop and cycling capabilities where feasible. Importantly, these requirements are differentiated by unit type, coal quality, and heating obligations, acknowledging technical and regional constraints. While low-carbon retrofits and intelligent control upgrades are encouraged rather than mandated, provinces are required to prioritise units with at least 10 years of remaining operational life, ensuring that retrofit investments deliver system value over a meaningful horizon.

In contrast, new coal units approved or constructed under this policy regime face significantly tighter design standards, effectively embedding flexibility and efficiency from the outset. New pulverised coal units are expected to reach minimum loads of around 25 per cent or lower, exhibit faster ramping performance, and comply with stringent efficiency benchmarks aligned with national energy consumption limits. Pilot “new-generation coal power” units are subject to even higher expectations, including sub-20 per cent minimum load operation, steeper ramp rates, enhanced automation, and a 10–20 per cent reduction in carbon intensity per unit of electricity compared to 2024 benchmarks. By raising the baseline for new builds while retrofitting the existing fleet, China’s regulatory approach signals a long-term intent to progressively narrow the operational gap between legacy coal assets and a future power system dominated by variable renewables.

Five-Year Plans as Binding Blueprints for Finance and Action

Beyond setting technical targets, China’s Five-Year Plans function as binding instruments that align finance, implementation responsibility, and accountability across the power sector. Once flexibility objectives are embedded in the national plan and detailed through NDRC implementation guidelines, they are translated into concrete project pipelines that determine access to public and state-directed capital. State-owned generation companies, including large central utilities such as Huaneng Group and the State Power Investment Corporation, issue green bonds explicitly earmarked for clean coal utilisation and flexibility retrofits, with

proceeds tied to meeting NDRC-defined technical thresholds. In parallel, policy banks such as the China Development Bank and the Export–Import Bank of China have extended low-interest loans to state energy groups for retrofit projects formally listed in state implementation catalogues derived from national plan targets. This central financing push is reinforced at the sub-national level, where provinces including Shandong and Inner Mongolia have established matching fiscal subsidies and special retrofit funds to co-finance projects and ensure local compliance with central mandates. Together, this layered financial architecture ensures that capital expenditure follows policy intent, effectively making access to finance contingent on retrofit execution and transforming Five-Year Plan objectives into enforceable investment decisions.

In contrast to India, wherein retrofit ambition often outpaces financial closure and implementation remains fragmented across utilities. China’s planning framework integrates targets, financing, and accountability within a single institutional cycle, enabling rapid and coordinated execution at scale. This alignment of planning authority and finance sets the foundation for the next phase of transition, where the focus shifts from intent to delivery, namely, the scale, pace, and technical execution of coal flexibility retrofits across the existing fleet.

Large-Scale Retrofit Programme: Modest Engineering, Massive Scale

Under the 14th Five-Year Plan, the retrofit target is for 200 GW, a volume that is almost equivalent to the entire coal-based thermal fleet of India. A defining feature of China’s transition has been the sheer scale of these thermal power plant retrofits. With an average plant age of approximately 12–15 years and a design lifetime of around 40 years, the fleet is significantly newer than India’s, which remains dominated by older sub-critical units. This younger asset base exhibits reduced technical barriers to retrofitting and limited concerns around thermal fatigue and material degradation, although boiler and wear-and-tear issues under flexible operation are an ongoing concern.

Currently, the Chinese coal units are already capable of operating at an MTL of 40 per cent or below, irrespective of the technology type of each unit. The new units under construction are now obligated to operate at low technical limits from the outset and go even lower in some provinces. Advanced technology units of ultra-supercritical and supercritical nature showcase no real engineering challenges in operating at low loads and operate flexibly. This is similar to the Japanese or other western coal boilers, showcasing parity in technological advancement of their coal fleet. The coal units utilise additional oil to maintain stability in low-load

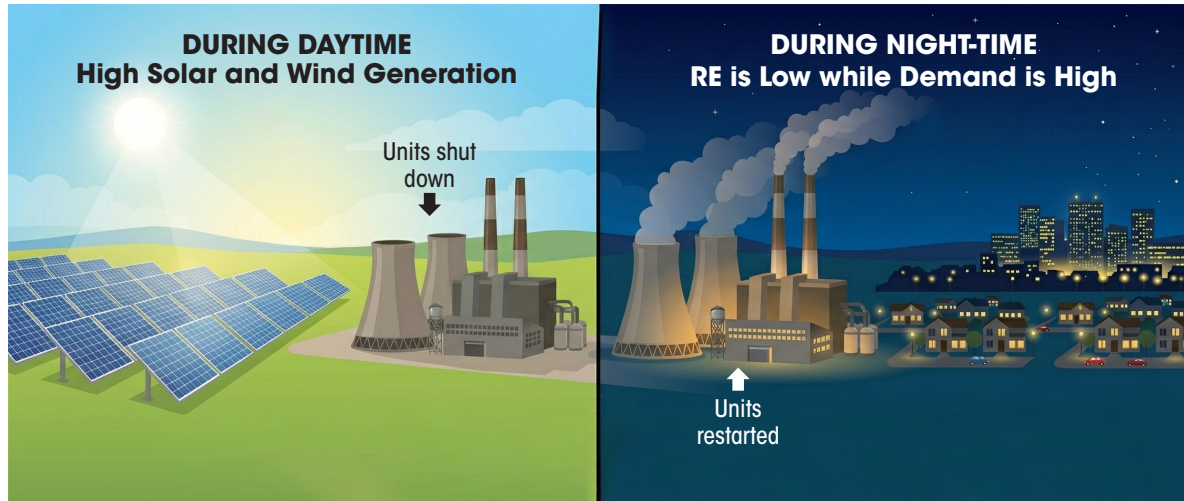
GANSU PROVINCE: TWO-SHIFT THERMAL OPERATIONS

Gansu province has emerged as a frontier for operational innovation in China's thermal power transition, particularly through the adoption of **two-shift (双班制) operating modes** at coal-fired power plants. This approach restructures plant staffing and dispatch schedules to enable coal units to cycle more frequently, operate at very low or zero load during renewable surplus periods, and respond rapidly to grid signals without compromising system reliability. The reform has been instrumental in enabling coal units to support large-scale wind and solar integration in one of China's most renewable-rich regions.

A landmark demonstration of this approach was achieved at the Jiuquan thermal power plant in July 2022, marking Gansu province's first successful intra-day start-stop peak-regulation operation for a coal-fired unit. Executed jointly by the State Grid Gansu Electric Power Company Dispatch and Control Center and the Jiuquan plant, the operation followed a "noon shutdown, evening restart" two-shift model. During midday hours—when wind and solar generation peaked and grid absorption became constrained—both Unit 1 and Unit 2 were shut down and placed on standby. As renewable output declined toward the evening peak and system demand tightened, the units were rapidly restarted and synchronised to the grid, demonstrating reliable start-stop capability within a single operating day (20–21 July 2022).

Figure 7: Two-Shift Operation Explained

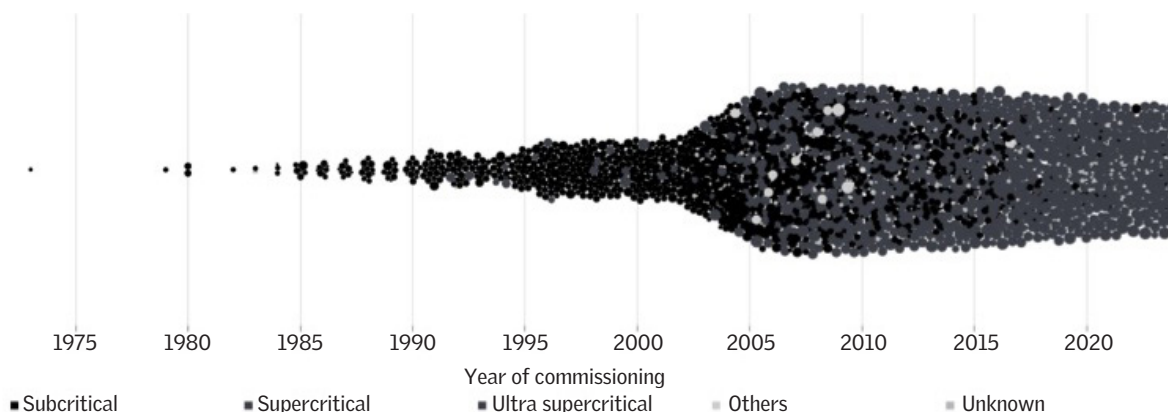
It showcases that a coal unit is turned off during the solar hours, restarts during the evening demand requirement, and then operates through the night.



Source: CSE analysis for illustration purpose

This operational shift delivered measurable system benefits. The two-shift operation increased renewable energy consumption capacity in the Hexi Corridor by approximately 198 MW, enabling the generation of an additional 4.356 GWh of clean electricity that would otherwise have faced curtailment. Notably, this was achieved at a plant comprising two 330 MW subcritical coal-fired units (660 MW total capacity) that also provide district heating and industrial steam, highlighting the feasibility of flexible, start-stop operation even under combined heat and power constraints. Gansu's experience illustrates how operational reforms, rather than major hardware replacement, can transform coal plants into responsive balancing resources for integration of renewable energy into the system.

Graph 31: China: Age Distribution of Operation Coal Units



Note: size swarm-plot dot corresponds to capacity size of the operation coal plant unit

Source: Bloomberg Global Coal Countdown Dashboard

operations. Importantly, for many units, the engineering interventions required to enable flexible operation were relatively modest, involving process control upgrades and operational optimisation rather than complete plant redesigns.

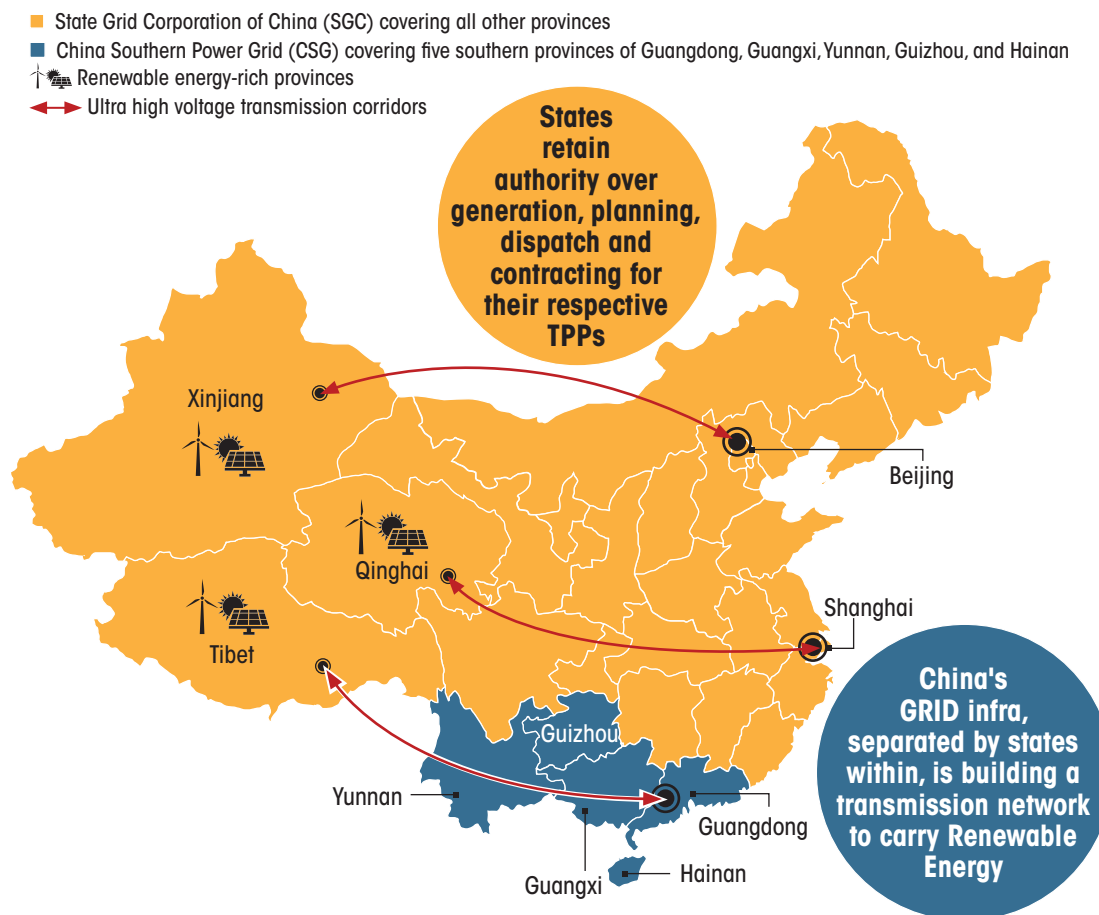
Operational Flexibility

China, like India, has never embraced gas as its major fuel source for power, relying instead on vast domestic coal reserves complemented by coal imports to meet its fuel needs. Rising variable power penetration owing to solar power installation has brought the challenge of grid frequency maintenance to its fore.

Grid Structure and State Dispatch Architecture

While India has a singular, synchronised national grid, China's power grid features a centrally planned and coordinated, yet regionally segmented structure, primarily divided into two vast, state-owned networks—the State Grid Corporation, covering northern, central, and eastern regions, and the China Southern Power Grid, serving the southern states. This architecture, further subdivided into smaller regional grids, stems from deliberate historical choices to manage the country's immense scale and geographic diversity. State governments retain significant authority over generation planning, dispatch, and contracting, driven by concerns over energy security, peak demand adequacy, and local economic stability. It enhances operational stability by isolating regional faults, allows for tailored management of unevenly distributed energy resources (like hydropower in the south and west and coal in the north), and facilitates the incremental integration of ultra-high-voltage transmission technology to link these regional blocks.

Map 2: China: Power Grid and State Connections



Source: CSE analysis of multiple PRC policy documents

While ultra-high-voltage (UHV) AC and DC transmission corridors have strengthened inter-regional connectivity, these links function largely as planned transfer channels rather than as instruments of fully centralised national dispatch. As a result, operational decisions remain decentralised, reinforcing province-level capacity additions—including coal power—while shaping the administrative and regulatory mechanisms through which flexibility reforms are implemented across China's power system.

Reforms for Flexible Operations

The state-wise built-up of coal power across China have enabled high rate over flexible power reserves in the system. The large legacy fleet in construction since mid-2000s, combined with continued new coal construction—driven by state planning considerations rather than coordinated system need—has contributed to an unplanned but substantial surplus of dispatchable capacity. Varying unevenly

across different provinces, the system may have flexibility reserve of between 20–50 per cent, allowing grid operators to meet power surges and maintain grid frequency. Thus, the nature of coal units is evolving from baseload assets to entities for meeting peak demand.

Contracted coal units connected to the grid are no longer assured a guaranteed number of annual operating hours that once underpinned returns on investment. Although coal plants were historically governed by a system of “Planned Utilisation Hours” (计划利用小时数), China’s power market reforms have fundamentally altered the nature of this mechanism. Coal plants are increasingly being repositioned as *flexible regulating power sources* to support the integration of intermittent renewable energy. Accordingly, remuneration is no longer limited to energy generation alone, but increasingly includes payments for capacity availability and the provision of ancillary services that support grid stability. As guaranteed “planned hours” have been phased out or substantially reduced, coal plants are now required to sell most of their electricity through market-based transactions, including annual or rolling bilateral contracts and, in some regions, spot markets. Consequently, coal units operate under de facto state-level annual generation caps, with allocations linked to projected electricity demand and the pool of contracted generators, resulting in broadly proportional utilisation across the fleet and reinforcing coal’s transition from guaranteed baseload generation to a shared system-balancing role. Operationally, dispatch decisions increasingly favour units that comply with flexibility requirements, reinforcing coal’s evolving system role.

Contracting and Dispatch as Enforcement Tools

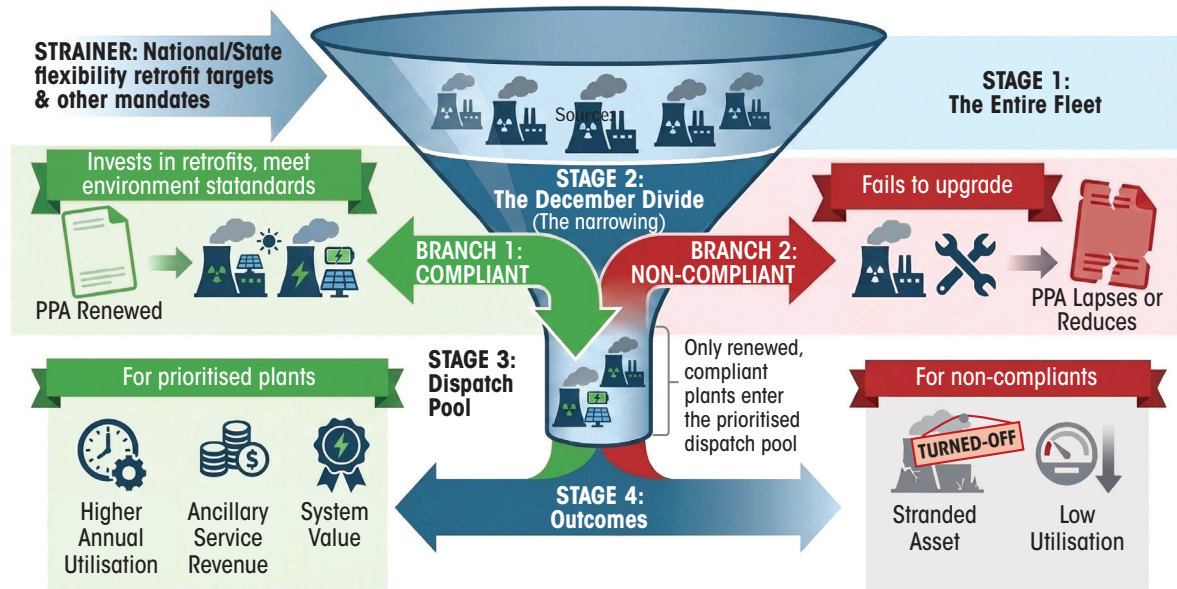
As flexibility reforms move from policy design to implementation, China relies on annual contracting and discretionary dispatch to enforce compliance. These mechanisms directly link market access and utilisation to demonstrated operational flexibility, ensuring that retrofit mandates translate into real system behaviour. Together, they anchor coal’s transition from guaranteed baseload generation to a performance-based, system-balancing role.

Contractual Renewal as a Policy Enforcement Lever

The annual Power Purchase Agreement (PPA) renewal cycle, typically concluded each December, has emerged as a critical administrative lever through which China enforces coal flexibility reforms. These annual medium and long-term bilateral contracts, signed one year in advance, cover approximately 80 per cent of total electricity demand and supply.

Figure 8: Chinese Policy: Funnel and Strainer System

Survival of the fittest journey for China's annual PPA compliance structure of TPPs



Συρρα: ΧΣΕ αναλυσισ οφ μιλτιπλε χηινεσε πολιχψ δοχυμεντο

Rather than serving as a routine commercial exercise, contract renewal functions as a structured compliance checkpoint used by state authorities and grid companies to assess whether coal units have undertaken planned technical upgrades aligned with national and state retrofit targets. Units that fail to meet expected flexibility, efficiency, or environmental benchmarks risk reduced contracted volumes or, in some cases, non-renewal altogether—effectively losing assured market access and revenue visibility. By directly linking contract continuity to technical modernisation, China has replaced earlier guarantees of planned utilisation hours with a **performance-contingent contracting framework**, embedding policy objectives into commercial outcomes and creating a strong, time-bound incentive for compliance without relying on explicit financial penalties.

Dispatch Preference as the Operational Reward

Coal plants in China are generally reluctant to operate flexibly due to higher operating costs, increased ramping burdens, and accelerated equipment wear, all of which can erode profitability. Rather than relying primarily on direct financial incentives, Chinese regulators have leveraged discretion in dispatch to reward compliant plants. Reinforcing contractual discipline is a reformed dispatch paradigm in which state grid operators exercise significant discretion when allocating load among coal units. Within the constraints of annual generation

caps and system requirements, dispatch decisions increasingly prioritise units that have completed flexibility retrofits and demonstrate superior operational responsiveness. These plants are rewarded through more favourable dispatch outcomes—such as steadier running profiles, higher utilisation within state specific caps, and enhanced participation in ancillary services—reflecting their ability to operate at lower minimum technical loads and ramp quickly to balance rising renewable variability. As a result, dispatch is no longer driven solely by bid prices or static merit-order considerations; instead it actively differentiates between flexible and inflexible assets.

China's flexibility framework further embeds enforcement at the operational level through mandatory automation and Automatic Generation Control (AGC) retrofits for both existing and new coal-fired units. Under the national implementation plan, existing units are required to achieve automated load control above the dry-wet transition point, with at least 90 per cent of AGC instructions executed without manual intervention. New or upcoming generation units are required to meet a higher threshold of at least 95 per cent AGC compliance across the full operating range. Compliance with AGC standards is not merely a technical upgrade, but a prerequisite for effective participation in flexible dispatch and ancillary service provision. Units capable of reliably following AGC signals are better positioned to provide frequency regulation, rapid ramping, and peak-shaving services, making them more attractive to grid operators during real-time dispatch decisions. In practice, this transforms automation into an operational reward mechanism; plants that invest in control system upgrades and demonstrate responsive AGC performance receive higher-quality dispatch, greater utilisation within annual caps, and preferential access to ancillary service revenues, thus reinforcing the link between technical capability and commercial outcomes.

This merit-based operational preference translates policy intent into day-to-day system operation, subtly penalising lagging units through reduced running hours while accelerating fleet-wide convergence toward a flexible, system-balancing role for coal power.

Capacity Payments as an Incremental Financial Incentive

Complementing contract and dispatch incentives, China has introduced a nationwide **capacity payment mechanism** to support coal-fired power plants. Effective since January 2024, the scheme provides a dedicated financial bridge for coal plants transitioning from baseload providers into flexible, system-balancing assets, as their inherent nature transitions toward a supporting and system-balancing role under high renewable penetration.

Managed by the National Development and Reform Commission (NDRC), this policy provides monthly standby payments to eligible public coal plants, designed to cover fixed costs during periods of low utilisation caused by high renewable output. The payments are calculated as a percentage (initially 30 or 50 per cent, increasing to at least 50 per cent nationwide from 2026) of a national fixed-cost benchmark of 330 yuan per kilowatt. Early analysis suggests that capacity payments reached over 100 billion yuan (× \$15 billion) in the first year, with some 70–100 per cent of coal plants receiving payments depending on state-wise implementation, boosting annual revenues by an estimated 5–8 per cent for typical generators.

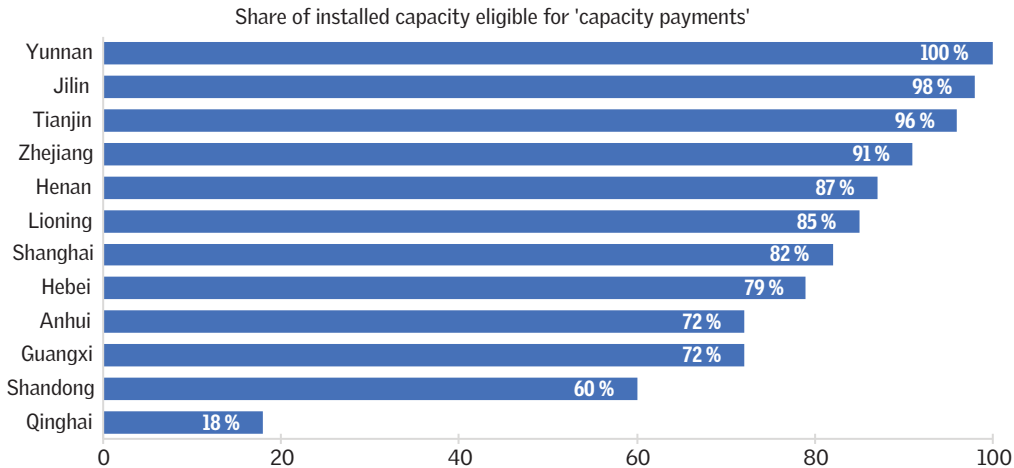
In 2026, under the *Notice on Improving the Generation-side Capacity Pricing Mechanism*, the 2023 capacity payment policy (as indicated in 2023 itself) has been updated. Under the new mechanism, the capacity payments are now referred to as “*Reliable capacity compensation mechanism*.” This underscores that the primary intent of the payment mechanism is to reward power utilities that support grid stability while meeting the challenge of peak power falling outside the solar generation hours.

The policy will allow state governments to pay out units that provide “Reliable Capacity”, i.e., provide stable electricity during peak periods. The 2023 policy only covered coal-based thermal power, but the new policy is now being extended to battery storage units and gas-based thermal units.

The new policy raises the limit of payment to a minimum of 50 per cent, with the flexibility to rise further based on state-specific market conditions. This will lead to additional payments to the coal fleet, which had already been transitioned to supply for peak demand and cushion the coal fleet’s economic viability, with breaking-even becoming even more challenging.

While designed to maintain energy security and stabilise plant finances as utilisation shifts downward, questions remain about the effectiveness of the payments in encouraging reduced operating hours or smoother integration of renewables, particularly given their broad availability across the fleet. Analysts from organisations like the Regulatory Assistance Project (RAP) note that it is restricted to coal, excluding alternative flexible resources—like energy storage or demand response—which could offer similar grid services.

Graph 32: China: Capacity Payments State-Wise Eligibility



Source: GEM analysis

Furthermore, state-wise implementation data shows that eligibility “guardrails” against inefficient or non-public plants appear to have been loosely applied. The broad inclusion risks prolonging the lifetimes of older units and could inadvertently incentivise new coal capacity, complicating assessments of whether the payments are genuinely reducing coal plant operating hours or primarily subsidising the existing fleet.

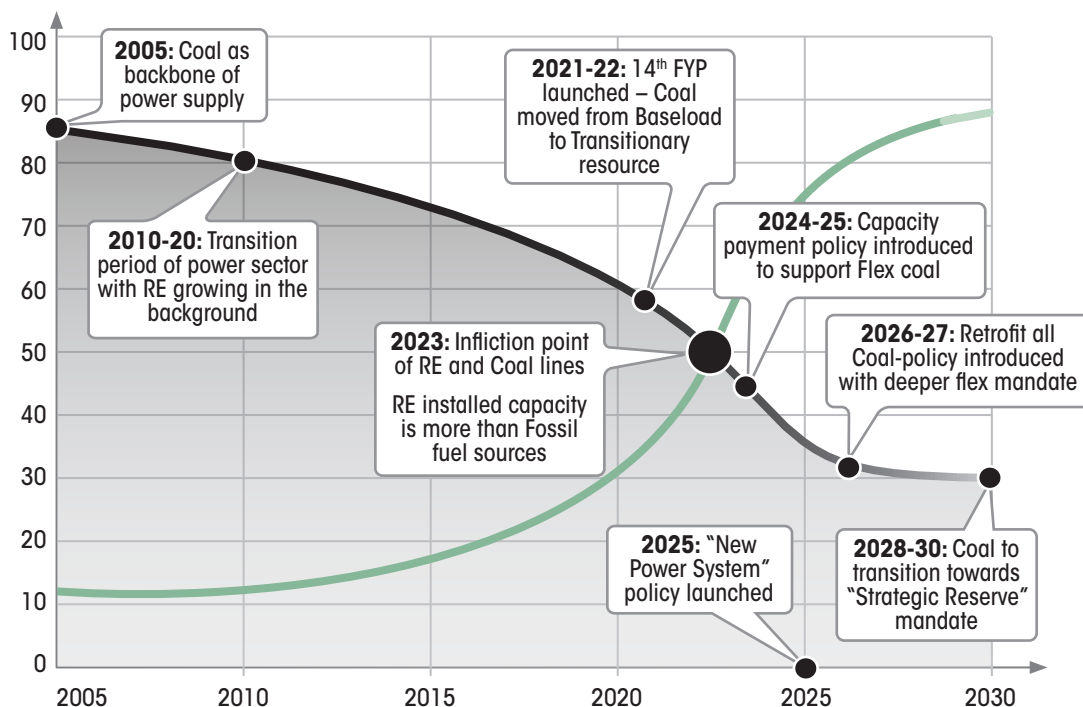
Beyond-Cost Incentives: Cadre Accountability and Merit Promotion

China’s push toward thermal power flexibility is reinforced by a powerful set of **beyond-cost incentives** embedded in its governance framework, most notably through the *Target Responsibility System* (目标责任制). Under this system, the implementation of Five-Year Plan objectives is treated as a binding administrative obligation rather than a discretionary policy goal. State level governors, senior energy officials, and heads of state-owned power enterprises sign responsibility agreements committing them to quantitative and qualitative targets, which increasingly include energy intensity reduction, renewable integration, and system flexibility outcomes. As coal flexibility retrofits are directly linked to these objectives, their successful execution has become an integral component of official performance evaluation, elevating technical delivery to a matter of political credibility and administrative competence.

Merit Promotion through Demonstrated Execution Capability

Within this framework, professional advancement is closely tied to an official's demonstrated ability to execute complex, nationally prioritised energy transitions. While individual promotions are rarely attributed publicly to a single technical outcome, consistent patterns are observable across the power sector. Senior executives within central energy SOEs who oversee large-scale retrofit programmes, pilot flexibility markets, or hybrid coal-renewable projects aligned with national strategy are often promoted within corporate hierarchies or reassigned to higher-responsibility roles. Similarly, officials in State Energy Bureaus or the National Energy Administrations that successfully design and implement flexibility pilots or manage renewable integration without compromising grid stability gain visibility and recognition, positioning them for advancement within the party-state system. Provinces such as Zhejiang, long used as reform pilots for electricity markets and digital grid management, have historically served as proving grounds where effective execution has translated into broader leadership opportunities.

Graph 33: China's Coal Reinvention Policy Timeline



Source: CSE analysis of multiple PRC policy documents

Penalties, Political Risk, and Enforcement Credibility

The incentive structure is reinforced by an equally credible penalty mechanism. Precedents from earlier national campaigns, most notably the “*War on Pollution*”, have established that persistent failure to meet centrally mandated targets can result in public reprimands, stalled promotions, or reassignment. This evaluative logic now applies to energy and carbon objectives under the “*Dual Carbon*” mandate, where state-level leaders chair local coordination groups and are personally accountable for progress. In this context, failure to deliver flexibility retrofits or to manage renewable integration risks becoming a professional liability. Together, merit promotion and penalty exposure create a governance environment in which coal flexibility reforms are enforced not only through financial instruments and market mechanisms, but through individual career incentives.

By embedding energy transition objectives into cadre evaluation systems, China aligns personal advancement with national strategy, making the implementation of thermal flexibility a high-stakes administrative priority rather than a purely technical or economic choice.

6.2 Germany – Flexibility Transition via Market Maturity

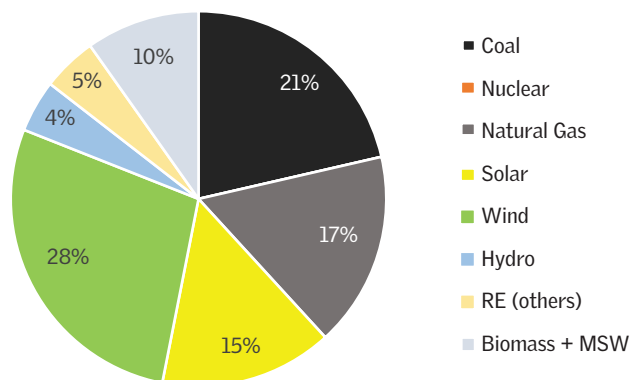
Germany’s experience demonstrates how large coal-based power systems can adapt to rising renewable penetration through systematic flexibility enhancement. As wind and solar expanded rapidly, the operational paradigm of the power system shifted from baseload stability to dynamic balancing. Germany pursued targeted retrofits, market reforms, and operational changes to make existing thermal capacity more responsive.

By 2024, Germany’s energy successfully transitioned to a renewable dominated mix with RE contributing 62 per cent, with the share of conventional fuels steadily declining over the years. Graph 35 illustrates the energy mix for FY 2024–25, showing that the share of coal and lignite-based thermal generation has declined by 7 percentage points since 2019, with an accompanying reduction in its absolute contribution as well (see *Graph 34: Germany: Power Generation by sources (2024–2025)*).

Germany’s energy transition is guided by a clear and consistent long-term policy commitment to climate neutrality. The country aims to meet at least 80 per cent of gross electricity consumption from renewable sources by 2030, with the power system becoming largely climate-neutral by 2035. This trajectory is anchored in law through the Energy Industry Act, which enshrines a national target of greenhouse

gas neutrality by 2045 and directs grid development planning toward a climate-neutral electricity system. Complementing these goals is a legislated coal phase-out under the *Act to Reduce and End Coal-Fired Power Generation (KVBG)*, sealed on 3 July 2020, mandating the complete exit from coal by 2038 and reinforcing long-term policy certainty for system transformation.

Graph 34: Germany: Power Generation by Sources (2024–25)



Source: German Energy Ministry

Energy Market Overview

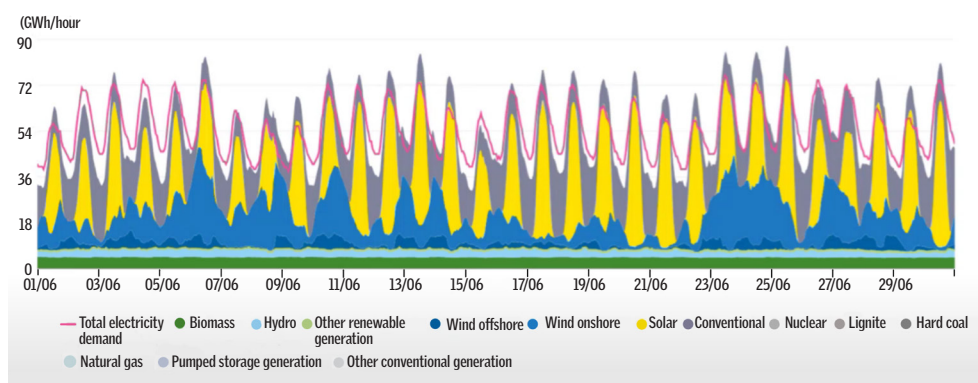
To successfully implement flexibilisation, an electricity market has been evolved into a non-discriminatory platform where all technically capable providers, including renewables, storage facilities, and flexible consumers compete on a level playing field. The market, relying on regulatory support, has been moved away from rigid, long-term structures toward high granularity, utilising **products with short lead times and 15-minute delivery blocks** to accurately reflect the variability of weather-dependent wind and solar power. Undistorted pricing signals, including the **acceptance of occasional price peaks**, allow the essential guide for market participants and ensure that available capacity is dispatched at the right time and to the extent necessary to maintain system equilibrium.

Its market design is bolstered by implementing several “no regret” measures, such as **reducing minimum bid sizes and shortening tendering periods**, for balancing capacity to lower entry barriers for smaller, more flexible units. The Federal Network Agency has worked to remove market barriers by introducing more frequent auctions and proposing adaptive sizing, which adjusts the volume of balancing capacity put to tender based on anticipated solar and wind supply. Furthermore, Germany has significantly **strengthened balancing responsibility** by pegging imbalance settlement charges to intraday exchange prices; this creates

a powerful financial incentive for parties to manage their own shortfalls through the market rather than relying on expensive system reserves. The system allows controllable power stations to follow demand in a power system where flexible resources respond to intermittent supply. The model relies on strengthened pricing signals to incentivise a technology-neutral mix of peaking capacity and demand-side management. To safeguard the transition and address investor uncertainty, the regulatory body has introduced a **“capacity reserve” that operates outside the competitive market**. This provides a safety net for rare emergencies without distorting the scarcity-based price signals required to drive long-term innovation and flexibilisation.

Currently, the typical load profile for June 2025 (see *Graph 35: Germany: Load Profile of GRID, June 2025*) indicates that, on most days, renewable generation meets a significant share of electricity demand, including during peak hours. Conventional sources increasingly operate in a balancing role, filling supply gaps when renewable output falls short or during periods when solar generation is unavailable.

Graph 35: Germany: Load Profile of GRID, June 2025



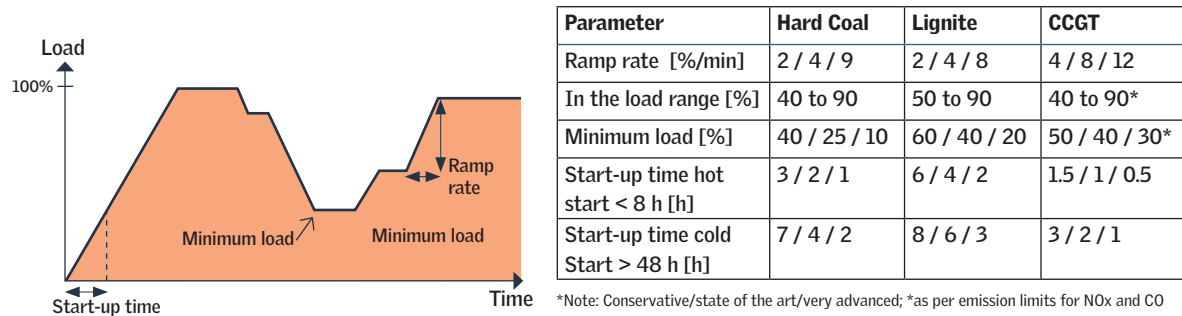
Source: Agora Energiewende

Although coal-fired power plants were traditionally designed for continuous 24/7 operation, they can now be operated in flexible cycles through significant structural and technological modifications. This transition was supported by Germany’s fully liberalised and open electricity market which provides the necessary framework to adapt to these shifting dynamics.

Transition to Flexible Coal

Notably, aging thermal power plants have demonstrated remarkable adaptability post the necessary retrofits. They are now adjusting their output on a 15-minute

Figure 9: Germany: Flexibility Parameters



Source: Agora Energiewende

basis in the intraday market and even on a five-minute basis in the balancing market to account for variations in renewable generation and demand. The regulatory measures required of the units were consistent and uniform in their application.

The primary focus is on flexibility parameters—minimum load, ramp rate, startup time, and shutdown time. The conservative ramp rate for hard coal and lignite is 2 per cent, while the state-of-the-art is 4 per cent; however, an advanced plant may reach 8 to 9 per cent. Ramp rates are typically higher for gas-based power plants. Additionally, the minimum load for hard coal is 40 per cent in a conservative scenario, but it can reach 25 per cent in a state-of-the-art scenario and as low as 10 per cent in an advanced one.

While addressing flexibility challenges necessitates a focus on technology upgradation, technology alone is not a panacea for rapid transformation. Yet, the notable aspect is the willingness of the industry players to implement the required retrofits. On the technical front, this includes optimising instrumentation and control systems (I&C) to handle varying load ranges, as well as updating O&M procedures. Beyond the mechanical aspect, the human element remains a critical barrier. Operators accustomed to full-load operations often hold apprehensions about system stability, showing resistance to change. Heavy reliance on process automation and optimisation of control loops to enhance grid stability reduces the human barrier in the intermediate period.

Key Differentiator

A key differentiator in Germany's transition has been the systematic expansion and strengthening of the electricity grid. As renewable generation increased rapidly, Germany prioritised grid reinforcement, expansion, and cross-border interconnections to ensure that electricity could be transported efficiently across

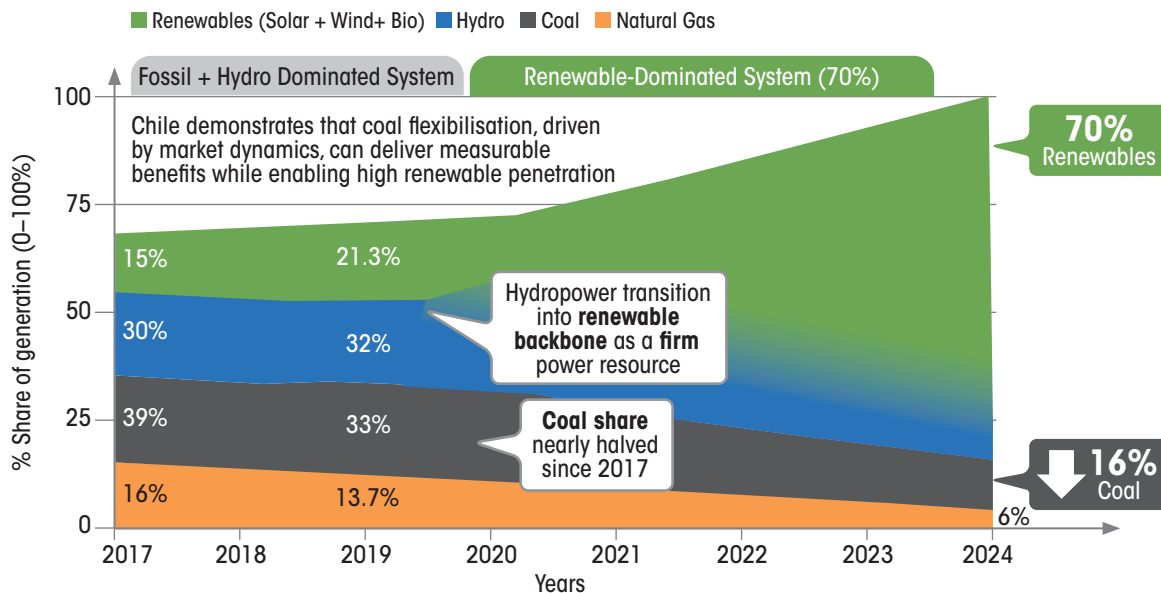
CHILE: FLEXIBLE COAL FOR SYSTEM WIDE SAVINGS

Chile, the South-American coastal nation mostly known for lithium exports in Indian policy parlance, stands out as a sovereign state that has achieved coal flexibility without a policy mandate for the same. The country has moved beyond the peak of coal-based emission of 30MtCO₂ in 2019 to 11MtCO₂ in 2023, despite an increase in overall electricity generation.

Chile's electricity generation mix has undergone a sharp structural transition, with renewables (solar, wind, hydro, and biofuels) expanding rapidly to dominate nearly 70 per cent of generation by 2024, even as total demand has grown at a modest scale of 2.3 per cent. Solar energy alone has emerged as a leading source, rising from under 8 per cent in 2019 to over 24 per cent in 2024, complemented by a doubling of wind energy's share simultaneously. The system's firm power and balancing backbone, i.e. hydro, natural gas, and coal combined, has contracted from ~78.7 per cent in 2019 to ~56.0 per cent in 2024, with hydropower now anchoring baseload operations amid declining fossil dependence.

Coal-based thermal power has undergone a sustained and steep phase-down, with its share declining from ~39 per cent in 2017 to ~33 per cent in 2019, and nearly halving further to ~16 per cent by 2024. Currently, it operates 3,117 MW of coal capacity and has committed to phasing it out by 2040.

Graph 36: Chile: Electricity Generation Transition (2017 Onwards)



Source: CSE analysis of Chile policy documents

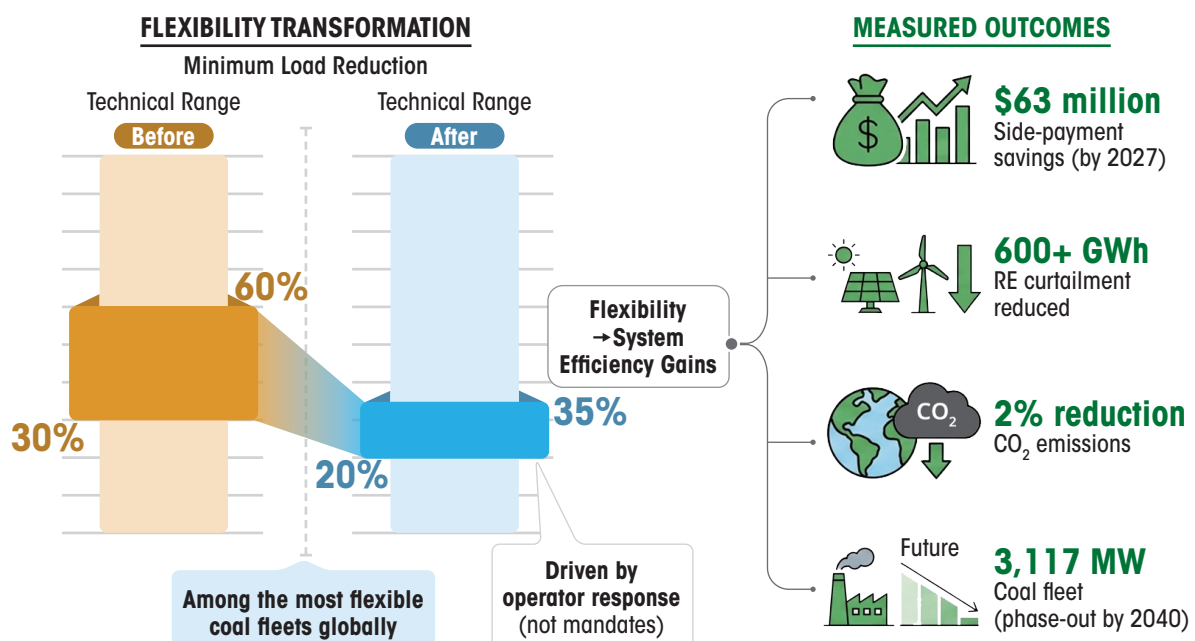
Yet, the transition to coal phase-out has not been immediate, with RE integration becoming a policy mandate from 2015 onwards. In that year, the government-initiated auction reform segmented supply blocks (day, night, and peak), enabling tailored RE bids. The RE 'must-run' status, coupled with auction reform, necessitated a lower operational load for coal-based thermal units.

Rising RE penetration increased cycling or ramping requirements, leading to higher maintenance costs and greater risk of technical failures. In response, operators lowered minimum load levels to manage wear and tear, while enhancing the operational flexibility and competitiveness of their plants relative to less adaptable thermal units. These reductions were driven largely by private operators, without targeted policy incentives for flexibilisation.

The country has progressively reduced the minimum load of its coal fleet from 30–60 per cent down to 20–35 per cent of nominal capacity, placing its plants among the most flexible worldwide. The estimated cost of implementation is US \$6–24 million (Rs 54–216 crore) for the entire Chilean coal fleet. Aggressive flexibilisation implementation has translated into savings of about US \$63 million in side-payment avoidance by 2027, with RE curtailment reductions of over 600 GWh and CO₂ emissions lowered by nearly 2 per cent.

Figure 10: Chile: System-Wide Benefits of Coal Flexibility

Showcasing how flexibility policy change has delivered quantified outcomes



Chile demonstrates that coal flexibilisation, driven by market dynamics, rather than mandates, can deliver measurable economic and environmental benefits while enabling high renewable penetration.

Source: CSE illustration of GiZ's 2025 policy reports

Coal flexibility has been effective in Chile because the country's power system combines high renewable penetration with a diversified generation mix, market mechanisms that reward flexible operation, and prior investments that lowered coal plants' minimum loads, creating an enabling environment for managing variability while maintaining system reliability and affordability. Coal power flexibilisation emerges as a cost-effective transitional tool, where it has been designed to enhance renewable integration, reduce curtailment, and deliver lower emissions and consumer benefits under clear policy and regulatory oversight.

regions and balanced in real time. This infrastructure development has enabled the system to absorb variability from wind and solar while ensuring reliability, reducing the need for rigid baseload operation and allowing conventional plants to operate more flexibly. Curiously, Germany does not impose a market cap on generators selling power into the market, allowing them to raise price substantially during Non-solar hours of the day. This is distinct to India, wherein market cap on electricity has been set at Rs 10/kWh of generation.

Equally important has been the operational shift toward responsive and economically driven dispatch of power plants. Conventional generators are no longer operated as fixed baseload units but are required to respond dynamically to system conditions. This market-aligned and system-responsive dispatch framework has transformed thermal generation into a balancing resource, enabling Germany to integrate high shares of variable renewables while maintaining grid stability.

6.3 Key Takeaways for India

International experience shows that large coal-based systems can transition toward flexible operation when technical retrofits are supported by strong institutional and market design.

China's journey underscores that thermal flexibility can be achieved at scale through a combination of modest technical retrofits, administrative dispatch incentives, and strong state support embedded in planning, financing, and enforcement mechanisms. It highlights the limits of flexibility in coal-heavy systems, particularly where plants are constrained by heat obligations or insulated from market signals. Administrative enforcement, including contract renewal, preferential dispatch, and performance-linked incentives, ensure that technical capability translates into actual system behaviour at scale. For India, the Chinese experience offers both encouragement and caution, indicating that flexibility must be supported by broader system solutions such as storage, market reform, and demand-side responsiveness.

Germany, by contrast, illustrates a market-driven pathway to flexibility. Integration within the European power market, strong cross-border interconnections, and mature price-based dispatch have enabled conventional plants to operate as balancing resources rather than fixed baseload units. Its experience shows how competitive market design, regional grid integration, and consistent long-term policy direction can create economic incentives for flexible operation. A level-playing electricity market, short-interval trading, strong balancing responsibility, and consistent long-term climate policy have collectively enabled conventional plants to operate flexibly while renewable penetration rises.

Taken together, these experiences suggest that flexibility is not achieved through plant retrofits alone. It requires coordinated policy direction, aligned financial and regulatory incentives, responsive dispatch practices, and supportive market or administrative frameworks. For India, this implies that scaling thermal flexibility will depend not only on technical upgrades but also on sustained institutional commitment, clear operational incentives, and broader power system reforms that enable flexible resources to be valued and utilised effectively.

7

COST ANALYSIS: FLEXIBILISATION AND ALTERNATIVES

Shadow cost of RE curtailment amounts to ~Rs 5,982 crore, comprising Rs 2,651 crore paid for unused RE and approx. Rs 3,331 crore for fossil fuel replacement

Flexibilisation results in a modest tariff impact, with CAPEX ranging 0.47–2.35 paise / kWh and OPEX incremental cost resulting in 8–15 per cent increase

Scaling BESS will require Rs 1.08–1.39 lakh crore (short-duration) and up to Rs 9.6 lakh crore (long-duration), with tariff impact ranging Rs 1.1–7.1/kWh

NTPC Mauda case shows BESS integration at existing TPPs significantly increases per-unit costs, compared to retrofit-based flexibilisation, reinforcing its lower-cost advantage for existing fleet



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India's transition toward flexible operation of coal-based thermal generation has entered an implementation phase, driven by recent tariff regulations and state-level adoption that bring a substantial portion of the thermal fleet under regulatory obligation. At the same time, the power system is undergoing structural change, marked by declining thermal utilisation due to renewable expansion, evolving demand patterns, and parallel plans for new coal capacity additions. These intersecting developments raise an important policy question regarding the economic rationale and system value of flexibilisation within an evolving generation mix.

This chapter is therefore intended to evaluate the cost implications and economic trade-offs associated with flexible thermal operation in India's changing power system context. It assesses capital expenditure, operational costs, tariff impacts, and system-level outcomes arising from flexibilisation, and situates these against alternative pathways for managing variability, with thermal generation coupled with battery storage systems. It details the cost of storage, its current scale, and the environmental concerns associated with it. It also notes the internal costs associated with RE curtailment and the environmental trade-offs it causes. By comparing these, the chapter examines how current policy strategies will influence consumer costs, investment allocation, grid efficiency, and emissions outcomes.

The cost estimates presented below are based on the CERC Compensation Methodology 2023–24. This framework provides quantified estimates of fixed costs and O&M components, including the life consumption of assets, and offers defined ranges applicable across the thermal fleet, enabling a system-level cost assessment. In contrast, the 2025 Tariff Regulations primarily set out the calculation mechanism for determining compensation during day-to-day operations and do not specify comparable fleet-wide cost benchmarks or explicitly account for life consumption within O&M. Accordingly, the 2023–24 methodology has been relied upon to estimate the broader cost implications of flexible operations. The assessment uses the CEA's 2023 phasing plan, with coverage of 196.7 GW of coal-based thermal capacity in India. Because the phasing plan provides unit-wise coverage under each phase, it has been used as the basis for the estimates given below.

Such an assessment is necessary because policy choices made today will shape medium-term infrastructure investments and long-term transition trajectories. Understanding the relative financial burden, operational implications, and opportunity costs of competing approaches is critical for informing regulatory

design, investment prioritisation, and system planning decisions. The analysis therefore aims to guide policy deliberation toward solutions that balance affordability, reliability, and transition alignment, establishing the analytical basis for the recommendations presented in subsequent sections.

7.1 Estimated CAPEX Cost of Flexibilisation

The CEA's phasing plan, 2023 covers **493 generating units** with a total capacity of **196.7 GW**, excluding coal-based thermal units commissioned after 2022. This exclusion is based on the premise that newly commissioned units require only minimal adjustments to operate at lower technical minimum loads of up to **40 per cent**.

Estimating the CAPEX associated with flexibilisation is necessary to assess the scale of financial resources required to implement the plan. The pilot phase has provided clarity regarding the nature of technical modifications required and has offered an indicative range of costs that may be incurred during wider implementation. For example, modifications undertaken at **NTPC Dadri Unit No. 6** resulted in a CAPEX of approximately **Rs 5.5 crore**. While this provides a useful signal of the order of investment involved, it should not be treated as a definitive benchmark for system-wide deployment.

In 2023, the CERC published a draft compensation methodology proposing that such CAPEX be recovered through adjustments to fixed costs over a five-year period. The methodology categorised the thermal fleet into three segments based on commissioning vintage. Units commissioned prior to 2004 were assigned the highest capital cost allocation, reflecting greater retrofit requirements, whereas units commissioned since 2011 were assigned the lowest allocation. The scale of cost allocation, together with the corresponding fleet size within each category, is presented in the table below (see Table 10: *CAPEX Estimates for Flexibilisation: Coal Plant Vintage Categories*).

Table 10: CAPEX Estimates for Flexibilisation: Coal Plant Vintage Categories

Coal Units (Based on Commissioning Date)	Suggested CAPEX (in Rs)	Scale of the Fleet Under Respective Categories Unit (Capacity in GW)
Prior to 1.1.2004	Rs 30 crore	164 (38.7)
Between 1.1.2004–31.12.2010	Rs 10 crore	75 (26.7)
Since 1.1.2011	Rs 6 crore	244 (125.4)

Source: Extrapolation of CEA's Phasing Plan, 2023 on CERC's Compensation Methodology, 2023

Based on the adopted methodology, CSE has estimated that the capital expenditure (CAPEX) required for flexibilisation is approximately **Rs 7,134 crore**.

Although current capacity is 227.8 GW, the estimate for CAPEX for non-included 31.1 GW is not estimated here, as it is excluded from the CEA's phasing plan. However, considering the underlying uncertainty in unit cost assumptions, the per-unit CAPEX may reasonably range between **Rs 6–30 crore**. Applying this range across the full implementation phasing plan yields a total investment requirement of approximately **Rs 2,958–14,790 crore**.

In April 2026, RRVNL has approached RERC with an in-principal approval for capital adjustments at the **Suratgarh TPP (660 MW)** for flexible operations. The cost estimation is **Rs. 17.51 Crore**, *for a post 2011 unit as Suratgarh was commissioned in 2021*. This highlights that the CAPEX estimate will remain near the upper threshold, owing to inflation and cost revisions in the future in line with forex valuation of INR in international economic markets. In totality, the expense will continue to remain within the above given threshold.

Deeper Breakup of the CAPEX Estimates

As the methodology distributes cost recovery over time, the required capital investment should be interpreted through a phased lens, using the CEA phasing plan as the implementation signal.

The ownership-wise disaggregation highlights the distribution of financial responsibility across stakeholder groups and provides an indicative view of the relative investment burden associated with flexibilisation deployment.

Across the entire implementation horizon, the plan encompasses 145 central, 178 state, and 160 private sector units. Based on the assumed cost range, the estimated capital investment requirement is Rs 870–3,350 crore for central sector units, Rs 1,068–5,340 crore for state sector units, and Rs 960–4,800 crore for private sector units.

Under Phase I, covering 91 thermal units, ownership is distributed across central, state, and private utilities in a ratio of 28, 27, and 36 units, respectively. Based on the assumed cost range, the total investment requirement for this phase is estimated at Rs 546–2,730 crore. Phase II includes 100 units, with an ownership split of 21 central, 17 state, and 62 private units. The corresponding investment requirement is estimated at Rs 600–3,000 crore. In Phase III, where the ownership distribution is 17 central, 40 state, and 44 private units, the estimated capital requirement

ranges between Rs 606–3,030 crore. Finally, Phase IV covers units distributed as 79 central, 94 state, and 18 private, yielding an estimated investment requirement of Rs 1,146–5,730 crore.

Taken together, this phased assessment highlights that the financial burden of flexibilisation is distributed unevenly across implementation stages, with later phases involving older units resulting in greater capital requirement.

Impact on Private Sector Units

As per the phasing plan, there are 160 privately-owned units. A glance over the estimated costs reveals a significant capital outlay, i.e., between Rs 960–4,800 crore. Yet, the actual cost impact is dependent upon the age of the fleet, as units installed since 2011 have a reduced modification requirement. Assessment of the age profile of the private-sector units under the phasing plan reveals that a majority of the fleet is newly built, with 123 units having been commissioned since 2011. The number of pre-2004 units, which may require greater modifications, is small, with only 13 units falling into this category. The remaining 24 units were commissioned between 2004–2010, resulting in an intermediate level of modification investment.

Therefore, the private-sector companies owning these thermal units will have an outlay at the lower range of the estimate. Furthermore, the CERC Tariff Regulations, 2024 will allow these costs to be passed down for recovery via fixed-cost tariff adjustments. The companies will thus only incur the expenditure in the short term. The scale of impact will further vary depending upon each company's fleet size.

Impact on State Sector Units

State-owned units constitute the largest share of the fleet covered under the CEA's phasing plan, accounting for **178 units**. The cost estimate is significant, ranging between Rs 1,068–5,340 crore. The purpose of this assessment is to identify the role of each corporation in the implementation of flexibilisation. As, the actual cost recovery will be from the consumers as a tariff pass-through, the capital cost burden will not fall on taxpayers, but rather on power consumers, including industrial units located within these states.

The age profile of these units is skewed toward older assets, with 93 units commissioned prior to 2004. In comparison, 57 units were commissioned after 2011, while the remaining 28 units fall within the intermediate commissioning

period of 2004–10. This distribution suggests that a significant share of the state-owned fleet may require deeper retrofits to enable flexible operation, implying relatively higher capital outlays.

Yet, the true assessment of cost requirement ought to be seen from the share of the disposal requirement on each power corporation of the respective states.

Table 11: Phase-Wise Assessment of Unit-Based Coverage for State Power Corporations

S. no.	State	Power Corporation	Phase 1	Phase 2	Phase 3	Phase 4	Total
1	Andhra Pradesh	APGENCO, APPDCL	4	-	4	8	16
2	Chhattisgarh	CSPGCL	1	1	2	5	9
3	Gujarat	GSECL	-	3	-	13	16
4	Haryana	HPGCL	-	-	4	-	4
5	Jharkhand	TVNL	-	-	-	2	2
6	Karnataka	KPCL	2	-	4	6	12
7	Madhya Pradesh	MPPGCL	2	4	1	5	12
8	Maharashtra	MAHAGENCO	4	3	7	13	27
9	Odisha	OPGC	-	-	2	2	4
10	Punjab	PSPCL	-	-	2	6	8
11	Rajasthan	RRVUNL	3	2	-	4	9
12	Tamil Nadu	TANGEDCO	3	-	-	12	15
13	Telangana	TSGENCO, SSCL	7	1	2	1	11
14	Uttar Pradesh	UPRVUNL	1	1	5	13	20
15	West Bengal	DPL, WBPDC	0	2	7	4	13
Total			27	17	40	94	178

Source: CSE analysis of CEA Phasing Plan, 2023

Overall, 15 power corporations are enlisted in the phasing plan, with the largest burden falling on the Maharashtra-owned MAHAGENCO, which accounts for 27 units. Notably, a large chunk of the obligation falls under Phase 4, whereas Phase 1 covers only four units. In general, in Phase 1 features nine power corporations, with the largest load being on the Telangana-owned TSGENCO with five units.

The state corporations face a lower burden in the first three phases, with a coverage of 27, 17, and 40 units across Phases 1–3, respectively. The structuring will allow state corporations to identify the necessary modifications needed for retrofitting their obligated units and to implement them in a time-bound manner. The state corporations can also utilise resource adequacy studies to identify long-term plans for the older units featuring in Phase 4, whether that involves transitioning them to two-shift operations or pursuing retirement. The cost burden recovery will be from the consumers and the next segment moves towards identification of the same in the next segment.

Impact on Consumers

The CERC Compensation Methodology, 2023 proposes placing a cap on annual cost recovery to moderate the impact on consumer tariffs and distribute the financial burden over a longer time horizon. Specifically, it recommends limiting CAPEX recovery in any given year to *one-fifth* of the total expenditure.

To assess the tariff implications of flexibilisation investments under Phase I, the additional fixed-cost recovery was estimated by distributing the capital recovery requirement across the expected annual generation of the modified fleet. Average plant load factor (PLF) values from the previous year (April 2024 to March 2025) were used as utilisation proxies to estimate annual generation, with sectoral PLFs assumed at **80.16 per cent** for Central units, **68.24 per cent** for State units, and **67.6 per cent** for Private units. Using the installed capacity and average PLFs for Central, State, and Private sector units, the total annual generation from the 51.08 GW fleet is estimated at approximately **321 billion units (BU)**.

When the recovery requirement of **Rs 109.2–546 crore** is spread across this generation, the resulting system-wide additional fixed cost is modest, amounting to roughly **0.0034–0.0170 Rs/kWh (0.34–1.70 paise/kWh)**. This indicates that the tariff impact of flexibilisation modifications, when recovered over operational output, remains limited in magnitude. A simplified straight-line recovery over five years has been assumed, without applying a capital recovery factor such as interest on the capital.

Ownership-wise disaggregation shows some variation driven by utilisation levels. Central sector units, operating at higher PLFs, exhibit the lowest incremental burden at **0.31–1.52 paise/kWh (122.8 BU)**, while state sector units, characterised by comparatively lower utilisation, face a slightly higher recovery range of **0.36–1.79 paise/kWh (95.1 BU)**. Private sector units fall between the two at **0.36–1.81 paise/kWh (104.6 BUs)**.

The estimated incremental fixed-cost impact for Phase I reflects the annual recovery permitted under the regulatory cap (one-fifth of total CAPEX). This recovery amount is applied each year over the amortisation period and therefore represents the yearly tariff adjustment associated with flexibilisation investments.

Extending the same approach to the CEA's phasing plan in totality, the additional fixed-cost recovery was estimated by spreading one-fifth of the total projected expenditure across the expected annual generation of the modified fleet. Applying average utilisation levels to the **196.7 GW** capacity identified in the phasing plan yields an annual generation of approximately **1,234 BU**. When the recoverable annual expenditure of **Rs 591.6–2,958 crore per year** is distributed across this output, the resulting system-wide incremental fixed cost is estimated at **Rs 0.0047–0.0235 per kWh (0.47–2.35 paise/kWh)**.

Ownership-wise variation reflects differences in utilisation and cost allocation. Central sector units exhibit an incremental recovery requirement of **0.20–1.02 paise/kWh**. Meanwhile, state sector units, driven by a larger share of older assets and comparatively lower PLFs, show a higher range of **0.30–1.52 paise/kWh**. Private sector units fall between the two at **0.23–1.14 paise/kWh**.

Table 12: Summary of Additional CAPEX for Flexibilisation Deployment

Scenario	Capacity Covered (GW)	Annual Recoverable CAPEX (Rs Cr)	Incremental Fixed Cost (Rs/kWh)	Incremental Fixed Cost (paise/kWh)
Phase I (Lower)	51.08	109.2	0.0037	0.37
Phase I (Upper)	51.08	546	0.0185	1.85
Full Deployment (Lower)	196.7	591.6	0.0047	0.47
Full Deployment (Upper)	196.7	2958	0.0235	2.35

Source: CSE analysis

One needs to note the gap between cost at generator level and the landing cost of electricity to the consumer. The landing cost will also incorporate the transactional costs of incorporating flexible operations at system level. Overall, the results indicate that even under system-wide deployment, the tariff impact of flexibilisation-related capital recovery remains moderate on a per-unit basis, suggesting that phased recovery mechanisms can enable implementation without imposing disproportionate pressure on consumer tariffs. This reinforces the financial feasibility of implementing such retrofits within existing regulatory recovery frameworks.

7.2 O&M Costs of Flexibilisation

Flexible operation affects the physical condition of generating units by accelerating component wear and reducing equipment life, particularly under frequent cycling and sustained low-load operation. This manifests through higher failure rates, more frequent replacement of components, and an overall increase in operation and maintenance (O&M) expenditure. Additionally, this encompasses the equipment life consumption, thus shortening the life of a coal unit in totality.

Recognising this, the proposed CERC Compensation Methodology, 2023 incorporates an assessment of life-consumption impacts within fixed-cost recovery by permitting increases in annual O&M costs linked to the extent of flexible operation. Drawing on technical assessments referenced in the methodology, O&M costs may rise by **9 per cent, 14 per cent, and 20 per cent** when units operate at **loading levels of 50–55 per cent, 50–45 per cent, and 45–40 per cent**, respectively. These increases apply across plant sizes and reflect the progressive escalation in mechanical and thermal stress as the operating load declines. The associated compensation is allowed based on actual low-load participation, with full eligibility contingent on flexible operation for at least **310 days in a year**, and proportionate recovery otherwise.

Table 13: Proposed O&M Cost Increase Owing to Flexible Operations

Unit Size (in MW)	Operation Loading (in per cent)	Fixed Tariff Increase Due to Increased O&M Cost (in Paisa/ kWh)
200	<55 to 50	6.70
	<50 to 45	10.42
	<45 to 40	14.88
500	<55 to 50	4.57
	<50 to 45	7.11
	<45 to 40	10.16
660	<55 to 50	4.12
	<50 to 45	6.40
	<45 to 40	9.14
800	<55 to 50	3.70
	<50 to 45	5.76
	<45 to 40	8.23

Source: CERC Compensation Methodology, 2023

The magnitude of the cost impact varies with unit size, with proposed annual O&M increases ranging from approximately **Rs 6.58–32.35 crore** across capacities between **200 MW and 800 MW** under the lowest operation band (45–40 per cent). For the purposes of fixed-cost assessment, the proposal relies on incorporating these percentage increases on the actual prices, using a benchmark price to integrate life-consumption effects into flexibilisation cost evaluation.

The methodology provides indicative estimates of fixed tariff adjustments arising specifically from increased O&M expenditure under flexible operation. These estimates show that the incremental fixed tariff attributable to higher maintenance costs ranges between **3.70 and 14.88 paise/kWh**, depending on unit size and loading level. The above-mentioned figures suggest the range of cost estimate for unit sizes between 200 to 800 MW operating within a load range of 55 to 40 per cent.

This quantified range offers a useful reference for disaggregating fixed-cost impacts within flexibilisation cost assessments. Noticeably, smaller subcritical units will require greater capital injection to operate under flexible loads, while newer, large-capacity units require lower capital injection. According to other industry estimates under the latest cost projections, a non-pit head subcritical unit will have additional O&M cost of 54 paise/kWh generation. These costs are lower for newer technology units of supercritical and ultra-supercritical, with an estimate of 30 paise/kWh generation. The higher costs arise from the expectation that coal plants will operate at lower utilisation levels, making it necessary to recover investments upfront unless the recovery period is extended beyond five years.

These estimates indicate that, alongside capital retrofit modifications, equipment damage ought to be assessed and paid under fixed-cost recovery, as long as the unit has complied with flexible operation-related regulations. While the latest CERC 2025 Tariff Regulations allow capital costs, *O&M costs are not included in the regulations*. Thus, in the present regulation, the mechanical losses to machinery are rendered invisible. Conclusively, non-inclusion of the life impact assessment of flexible operations acts as a deterrent in adoption by thermal units.

The next section provides the detailed assessment of per day cost of flexible operations, including elements such as life consumption. These aid in arriving at the overall cost of flexible operations.

SHADOW COST OF RE CURTAILMENT

RE curtailment refers to the reduction of electricity generation from renewable sources, such as solar and wind, even when that power is available. This typically occurs when the grid is unable to absorb all the renewable energy being generated due to system constraints. Curtailment happens in two main ways. First, it occurs through short-term operational interventions, such as TRAS, where system operators temporarily reduce renewable output to maintain grid stability during periods of excess supply or network constraints. Second, it happens through longer-duration sustained curtailment, where renewable generation is backed down or not scheduled for extended periods due to persistent system limitations.

CSE analysed the scale of RE curtailment using data compiled from GRID-India's daily VRE reports between April 2025 and March 2026. Over the assessed period, solar energy amounting to 7,136.39 GWh and wind energy amounting to 486.99 GWh has been curtailed. In totality, **7,623.38 GWh or 7.62 Terawatt of energy** was curtailed.

The procedure creates a "double whammy" for consumers by incurring shadow costs on two fronts. Consumers pay for the curtailed renewable energy regardless of whether it is actually delivered, while simultaneously bearing the costs of fossil fuels that could have otherwise been avoided.

Drawing from the curtailed figures mentioned above, the shadow cost for solar and wind energy can be computed by multiplying the total curtailed energy by the weighted average cost of each source, as mentioned in the NITI Aayog's Energy Dashboard. As illustrated in the following table, the estimated cost of this curtailment amounts to **Rs 2,651.32 crore** (see Table 14: RE curtailment cost assessment).

Table 14: RE Curtailment Cost Assessment

Energy Source	Curtailed Energy (in GWh)	Cost Per Unit (Rs/kWh)	Total Cost (in Rs crore)
Solar	7,136.39	3.46	2,469.19
Wind	486.99	3.74	182.13
Total	7,623.38	—	2,651.32

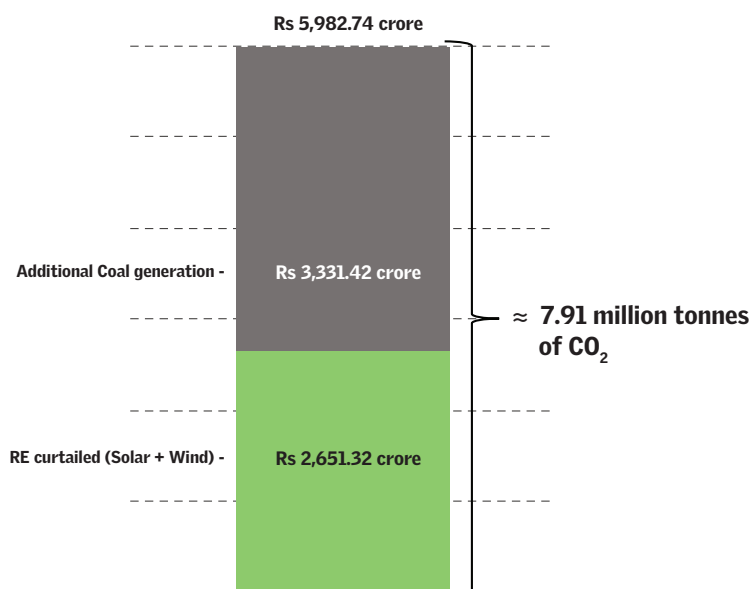
Source: CSE analysis

Subsequently, to understand the full scale of the economic impact, the cost of fossil fuel replacement must be analysed. This is calculated by multiplying the total curtailed renewable energy (7,623.38 GWh) by the weighted average cost of coal (Rs 4.37/kWh). Thus, the fossil fuel costs borne by consumers to compensate for this curtailed energy total **Rs 3,331.42 crore**.

Overall, consumers are penalised twice, once for the unused renewable energy (Rs 2,651.32 crore) and again for the fossil fuel (Rs 3,331.42 crore). This brings the total economic burden to **Rs 5,982.74 crore**, underscoring the "double whammy" effect of RE curtailment. The cost to the system in actuality will be elevated as the landing cost of generation at consumer level is greater than the average tariff.

Furthermore, there is a significant environmental cost, as reliance on fossil fuels generates unnecessary carbon dioxide emissions. According to the CEA's CDM-CO₂ database (2023), the emission factor for coal is 1.038 t/MWh. To quantify this negative externality, the net CO₂ emissions, derived by multiplying the emission factor by the total curtailed energy, amount to approximately **7.91 million tonnes**.

Figure 11: Total Shadow Cost of RE Curtailment (FY 2025–26)



Source: CSE analysis

Taken together, the financial and environmental impacts demonstrate that renewable curtailment is not merely an operational inefficiency but a systemic cost burden. Consumers effectively finance unused clean energy, pay again for fossil replacement, and absorb the associated emissions externality in the form of avoidable carbon dioxide releases and their broader environmental and health implications. Curtailment therefore manifests as a structural misallocation of system resources, with its shadow costs undermining both economic efficiency and decarbonisation objectives.

7.3 Operational Cost Covered for Flexible Operations

To estimate the potential tariff implications of flexible operation, the analysis begins with the average variable cost of the coal fleet for 2024–25 (units commissioned between 1990 and 2029), which is taken as **Rs 2.925/kWh (NITI Aayog’s India Energy Portal)**. This value serves as the baseline tariff. Using estimates from the CERC compensation methodology, which quantifies the increase in variable cost under flexible operation, percentage impacts were applied to this baseline. The methodology assesses units across size classes ranging from below 200 MW to 800 MW and evaluates degradation across three MTL bands: 50–55 per cent, 50–45 per cent, and 45–40 per cent. For the purpose of bounding the cost range of flexibilisation, the extreme values were used; assuming the entire fleet operates for seven hours at the lowest operation band (45–40 per cent), the tariff increase is

estimated between **8.52 per cent** and **14.86 per cent**. Applying these percentages to the base tariff produces incremental charges of **Rs 0.249/kWh (24.9 paise)** and **Rs 0.434/kWh (43.4 paise)**, raising the tariff to **Rs 3.174/kWh** and **Rs 3.360/kWh**, respectively. These represent upper-bound estimates, and actual impacts are expected to lie between these values.

To translate these unit costs into system-level implications, the additional tariff was applied to coal generation corresponding to seven hours of operation (solar hours) in 2024–25. Using the total annual generation of **1,331,866.97 GWh** by the full coal-based fleet in India, the average hourly generation was estimated at **152.04 GWh**, yielding **1,064.28 GWh** over the seven-hour period. At the base tariff of **Rs 2.925/kWh**, the cost of this generation would be approximately **Rs 310.8 crore**. Incorporating flexibilisation-related increases raises the total expenditure to **Rs 337.3 crore** and **Rs 357.0 crore** under the lower-impact and higher-impact scenarios, respectively. Therefore, the actual annual increase in cost will be **Rs 26.5 crore** under the lower-impact scenario and **Rs 46.2 crore** under the higher-impact scenario.

Table 15: Summary of Additional Payout Assessment Owing to Heat Rate Degradation

Scenario	Total Paid for Flexible Operations of the Entire Fleet on a Per Day Basis (in Rs crore)	Extra O&M Cost Paid for Flexible Operation on a Per Day Basis (in Rs crore)
BASE (NO INCREASE)	310.8	-
+ 8.52% tariff	337.3	26.5
+ 14.86% tariff	357	46.2

Source: CSE analysis

These calculations illustrate the scale of additional short-duration system costs associated with flexible operation, while reinforcing that the realised impact will depend on actual load levels and fleet composition. The actual degradation cost will be below the suggested figures, as with rising RE penetration during daytime operations, the generation during the solar hour period will be lower than the current CSE estimate. Additionally, the cost will be individual unit-based, depending upon the average degradation suffered. One notable caveat here is that some units on specific days may suffer higher degradation resulting in higher costs.

Furthermore, the additional secondary fuel requirement due to start-stop operations is not ideally reflected in the above figures. These costs may rise as

adoption of two-shift operations become necessary owing to greater RE penetration. Subcritical units from the pre-2004 commissioned vintage, especially those more than 25 years old, will endure greater secondary fuel requirement. This is because they are planned for two-shift operations, which will result in daily start-stop cycles of these units. The expense will be incurred at the consumer level that will be based on actual costs and will be slightly elevated in light of final system costs.

Having examined the capital, operational, and tariff implications associated with flexibilisation of coal units, the analysis now turns to other emerging alternative pathways as substitute to unit system flexibility, beginning with storage-based solutions such as battery integration with thermal and renewable assets.

7.4 Alternative Option: Battery Storage for Coal Units

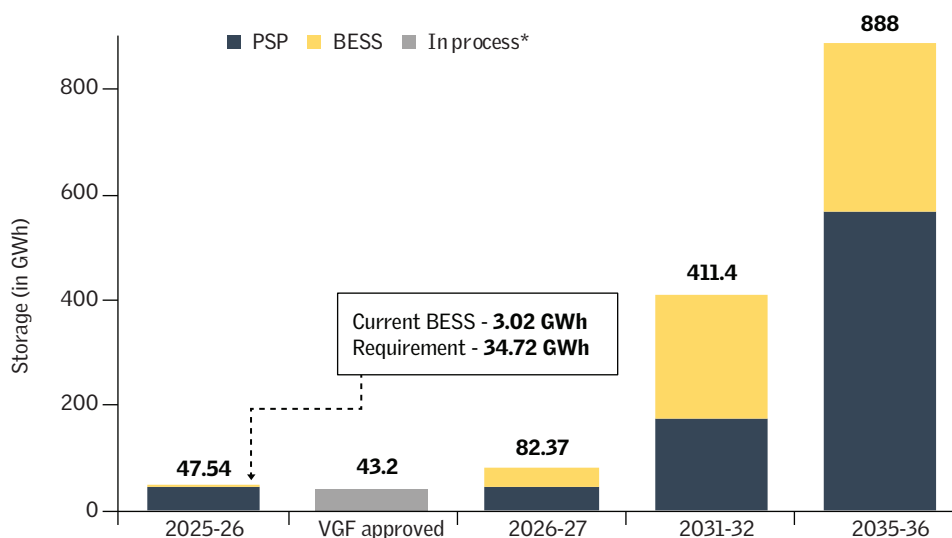
Utility-scale lithium-ion battery storage emerged from advances in electrochemical energy storage originally developed for portable electronics and electric mobility. In power systems, battery energy storage has been deployed to manage renewable intermittency by smoothing short-term supply-demand imbalances, supporting grid stability, and minimising the loss of available renewable generation.

State of BESS in India

By 2025, India's BESS operational capacity stands at only 205 MW or 0.5 GWh. As per the CEA's National Electricity Plan (NEP) 2023, the energy storage capacity requirement is projected to be 82.37 GWh (47.65 GWh from PSP and 34.72 GWh from BESS) in the year 2026–27. This requirement is further expected to increase to 411.4 GWh (175.18 GWh from PSP and 236.22 GWh from BESS) in year 2031–32. Further, CEA has also projected that by the year 2047, the requirement of energy storage is expected to increase to 2380 GWh (540 GWh from PSP and 1840 GWh from BESS), due to the addition of a larger amount of renewable energy in light of the net zero emissions targets set for 2070. India's Union Ministry of Power has approved a Viability Gap Funding (VGF) scheme for 43.2 GWh of BESS in 2025.

Projects currently under construction and already allotted indicate a preference for a two-to-four-hour storage cycle in India. However, longer duration BESS is a long-term technological need. NTPC's NETRA recently commissioned the country's first long-duration BESS utilising an MWh-scale Vanadium Redox Flow Battery (VRFB) with a capacity of 3MWh (0.5MW x 6hours). This is currently only in the research and development (R&D) phase. VRFBs differ from lithium-ion battery as the aqueous electrolyte used is non-flammable, making them safer for large-scale use. The lifespan is over 20 years and can operate for up to 12 hours.

Graph 37: India – State of BESS: Requirement and Deployment



Source: CSE analysis of multiple official reports

In terms of BESS projects, India's contracted capacity for long duration energy storage (LDES) is minimal.

Internationally, LDES has seen an uptick in adoption as it is needed to completely replace conventional firm power assets off their respective grids. Although two-to-four-hour storage supports solar shifting and grid stability today, deeper renewable penetration will progressively increase reliance on long-duration energy storage. In 2026, Australia's AusEnergy Services (ASL) has implemented LDES totalling 1.17 GW/11.98 GWh, with a target of reaching 42 GWh by 2034. However, to support their local VRFB manufacturing, the government has allocated US \$150 million (Rs 1,350 crore) in development of 500 MWh facility.

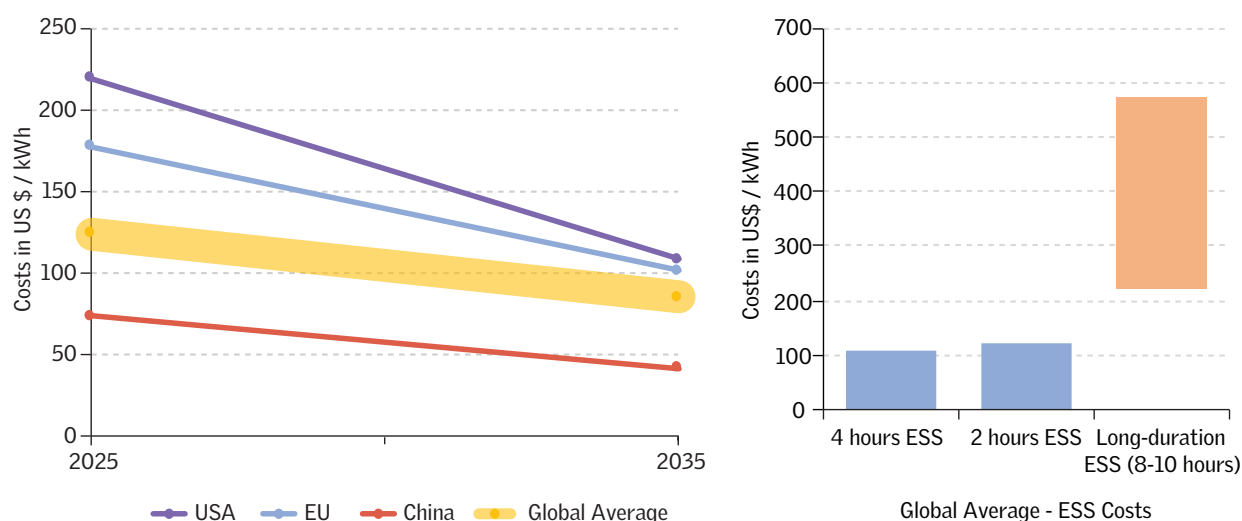
Global Outlook on BESS Cost Trends

Cost trends for short-duration battery storage indicate substantial declines in recent years, improving their attractiveness for grid applications, such as solar shifting and peak support. In 2025, the global average turnkey price of lithium-ion battery energy storage systems stood at approximately US \$117/kWh (×Rs 10,600/kWh), representing a significant reduction from earlier years. Average system costs were observed at US \$124/kWh (×Rs 11,230/kWh) for two-hour duration systems and US \$110/kWh (×Rs 9,970/kWh) for four-hour duration systems, with notable regional variation. China exhibited the lowest installed costs at around US \$73/kWh (×Rs 6,610/kWh), compared to roughly US \$177/kWh (×Rs 16,040/kWh) in Europe and US \$219/kWh (×Rs 19,840/kWh) in the United States. Forward

cost expectations suggest continued divergence, with projected 2035 turnkey costs for four-hour systems estimated at US \$41/kWh (×Rs 3,710/kWh) in China, US \$101/kWh (×Rs 9,150/kWh) in Europe, and US \$108/kWh (×Rs 9,780/kWh) in the United States, indicating ongoing cost compression driven by manufacturing scale and supply-chain concentration. New tenders allocated in Q1, 2026 aim for a further cost reduction with some tenders for short duration BESS coming at sub US \$100/kWh range. However, one needs to note their actual execution costs in the coming years. The depreciation of INR in 2026 will impact costs as India is heavily reliant on imports for this technology.

In contrast, long-duration electrochemical storage continues to face substantially higher capital intensity. For intraday storage systems sized at 100 MW with 10-hour duration, total plant capital costs were estimated in 2025 to range between US \$220/kWh (×Rs 19,930/kWh) and US \$572/kWh (×Rs 51,820/kWh), reflecting technology and configuration uncertainty at longer discharge durations. Cost reductions are anticipated over time, with projections indicating a narrower range of US \$244/kWh (×Rs 22,100/kWh) to US \$358/kWh (×Rs 32,430/kWh) by 2030 for similar systems. These figures highlight the persistent cost differential between short-duration and long-duration storage, underscoring that while longer-duration solutions may enhance system reliability and flexibility under high renewable penetration, their higher upfront capital requirements remain a key constraint on large-scale deployment.

Graph 38: Cost Trends of BESS: India and Global



Source: CSE analysis of multiple official reports

Indicative domestic benchmarks suggest that battery storage costs in India remain broadly aligned with global trends when expressed in installed capacity terms. As per industry analysts, a **four-hour storage system typically priced between Rs 3.5 crore and Rs 4.5 crore per MWh**, the implied cost range reflects the capital intensity associated with multi-hour energy capacity rather than power capacity alone. When viewed alongside international turnkey system benchmarks presented earlier, this range indicates that Indian project costs fall within the lower-to-mid portion of observed global cost bands for short-duration storage, particularly when accounting for supply-chain localisation and project-specific balance-of-system variations. This comparison suggests that while domestic deployment conditions remain cost-sensitive, current pricing levels do not materially diverge from global market signals. Despite growing international interest, utility-scale LDES has seen negligible deployment in India, where investment and policy focus continue to favour shorter-duration storage solutions.

Estimating BESS Deployment Requirements at TPPs in India

Scepticism surrounding flexible operations, particularly ramping requirements and their impact on unit life, is seen as a significant challenge by coal plant operators in India. This scepticism, along with the lack of tariff support that matches the flexible operations, has resulted in looking for an alternative idea of repurposing utility-scale lithium-ion battery storage or BESS at coal-based thermal power plants.

This approach implies that the phased capacity identified for flexible operation would instead deploy BESS capable of absorbing the load that would otherwise be handled through ramping, corresponding broadly to the operating range between 55 and 40 per cent MTL. To assess the scale of the transition, we need to identify the aggregate battery storage capacity at the outset. Using the CEA's CDM-CO₂ database (2023) as the baseline for detailed unit-wise fleet composition, the aggregate coal capacity considered is approximately 205.2 GW. Battery storage sized to buffer 15 per cent of this capacity over a six-hour duration will translate into a requirement of roughly **30.8 GW** of BESS power capacity, corresponding to about **184.7 GWh** of energy storage.

Applying long-duration BESS cost benchmarks to the estimated requirement of **30.8 GW/184.7 GWh** implies a substantial capital commitment. At current cost levels, as indicated in passages above, deployment would correspond to roughly **Rs 3.7–9.6 trillion (Rs 3.7–9.6 lakh crore)**. Even under future projected cost scenarios for LDES, the investment envelope remains large at approximately **Rs 4.1–6.0 trillion (Rs 4.1–6.0 lakh crore)**.

Even if short-duration BESS is deployed, i.e. four-hour cycle system, benchmark project-level systems costs stand at approximately Rs 3.5–4.5 crore per MW. The corresponding investment requirement shall be **Rs 1.08–1.39 lakh crore**. This can be corroborated with the latest allotment at NTPC Mouda thermal unit, where a 400 MWh tender was allotted at Rs 487.77 crore, resulting in an outlay of Rs 12,200 per kWh (see *Table 16: Cost Assessment of BESS Deployment at TPPs*).

Table 16: Cost Assessment of BESS Deployment at TPPs

Storage scenario	System size assessed	Normalised cost benchmark of BESS (In per kWh)	Estimated capital requirement	Per unit cost (₹/kWh) 15-year recovery period
LDES (Current Costs)	30.8 GW/184.7 GWh	₹19,930–₹51,820	₹3.7 - 9.6 trillion (₹3.7 - 9.6 lakh crore)	₹2.7–₹7.1
LDES (Projected Costs)	30.8 GW / 184.7 GWh	₹22,100–₹32,430	₹4.1 - 6.0 trillion (₹4.1 - 6.0 lakh crore)	₹3–₹4.5
Short-Duration BESS (4-hour cycle)	30.8 GW / 123.2 GWh*	₹8,750–₹11,250	₹1.08 - 1.39 trillion (₹1.08 - 1.39 lakh crore)	₹0.8–₹1
Utility-scale BESS Tender Benchmark (NTPC Mouda)	0.4 GWh	₹12,200	₹487.77 crore	~ ₹1.1
Utility-scale BESS Tender Benchmark (NTPC Gadawara and Khargone)	0.570 GWh	₹13,614	₹776.13 crore	~ ₹ 1.24

Source: CSE analysis

Extrapolating the CAPEX into a per-unit cost for the energy delivered over a 15-year time-period, highlights the scale of investment and the subsequent cost impact. Currently, the average fixed cost of coal is **Rs 1.49 per unit**, and adding BESS at thermal will almost double the cost, as the NTPC Mouda tender estimation highlights. Furthermore, even if one ignores the additional carbon resulting from the BESS running on coal power, the cost impact of BESS installation is prohibitively more expensive. It highlights the structural capital intensity associated with BESS with thermal at scale, particularly when evaluated against alternative flexibility pathways.

Cost Assessment of the Proposal

In 2024, the global aggregated installed battery energy storage capacity amounted to approximately 329 GWh, with the projected pipeline for 2027 expanding to around 1,279 GWh. Furthermore, the total deployed capacity for the first half of 2025 sits at 86.7 GWh of battery energy storage system (BESS) capacity—a year-on-year increase of 54 per cent—while the pipeline for the full year is currently just over 412 GWh.

India's own target for two–four hour BESS stands at 47 GW/236 GWh by 2031–32. Viewed in a global context, India's storage trajectory remains comparatively

limited, underscoring that strategic allocation of investment across competing deployment pathways will materially influence the direction and effectiveness of the energy transition.

The BESS tender at NTPC Mouda is expected to be completed within approximately fifteen months from January 2026, placing its implementation timeline broadly in line with flexibility modification schedules. However, the associated capital expenditure requirements are significantly higher, adding **~ Rs 1.1 per kWh over 15-year time-period in fixed costs**, creating risks of investment diversion and congestion within already constrained financing channels. Similarly, the NTPC Gadarwara and Khargone tenders, for aggregate 570 MWh of BESS with 2 cycles / 4-hour storage result in pure CAPEX of **~ Rs 1.24 per kWh**. The actual costs including O&M will rise further, creating greater systemic cost on per unit of electricity.

Grid-scale battery storage technologies were originally developed to enable the displacement of fossil-based generation by supporting renewable integration and reducing carbon-intensive injections into the power mix. Deploying such storage alongside coal-based thermal assets therefore represents a departure from this foundational objective.

In the present context, where India's battery storage ecosystem remains nascent and capacity for deployment is still evolving, prioritising investment toward renewable-linked storage applications is both necessary and time-sensitive. Locking substantial capital into storage systems that primarily support thermal generation and being run by fossil fuels risks crowding out investment in renewable storage, thereby undermining transition objectives. In this sense, allocating scarce financial resources to thermal-linked storage deployment constitutes a backsliding step.

7.5 Evaluation of Options: A Cost Benefit Analysis

The comparative assessment undertaken in this chapter demonstrates that flexibilisation of coal-based thermal units represents a financially moderate pathway for enabling grid responsiveness relative to storage deployment at thermal sites. Estimated capital requirements for flexibilisation across the **196.7 GW fleet** lie in the range of **Rs 2,898–14,490 crore**. Even when accounting for operational degradation impacts, system-level cost increases remain bounded, with short-duration flexible operation translating to additional expenditures of roughly **Rs 26.5–46.2 crore on a per day basis for the entire system** over the assessed generation window.

With annualised tariff impacts limited to approximately **0.47–2.35 paise/kWh in fixed costs**, suggesting that flexibilisation imposes incremental rather than structural financial burdens. Importantly, declining plant load factors associated with rising renewable penetration are likely to moderate operational expenditure pressures over time by reducing total generation volumes, partially offsetting degradation-related cost impacts and reinforcing the affordability of flexible operation.

In contrast, substituting ramping functionality with battery storage at thermal plants entails significantly higher capital commitments. Meeting the assessed flexibility envelope would require storage deployment of approximately **30.8 GW/184.7 GWh**, implying investment levels of **Rs 3.7–9.6 lakh crore** under long-duration cost structures and **Rs 1.08–1.39 lakh crore** even under short-duration configurations. This translates into a per unit fixed cost recovery in the range of **Rs 0.8–7.1 over 15-year period**.

On the CAPEX level, the expenditure between BESS to flexible operation retrofit amounts to a **600 per cent–31,000 per cent higher magnitude**. These magnitudes exceed flexibilisation expenditure by orders of magnitude and introduce carbon lock-in, as these BESS will be powered by fossil fuels. Furthermore, they risk capital diversion in a system where storage deployment capacity remains limited. Moreover, deployment of storage at coal sites does not address the structural inefficiencies that result in RE curtailment and frequency mismatch.

Unlike thermal flexibilisation, which enables multiple ramping across 24-hour demand cycles, a BESS deployed at a thermal unit is inherently constrained by its energy capacity and discharge duration. Consequently, it may not be able to accommodate successive intra-day variations, which are quite common as reflected in the above given analysis, once its stored energy is exhausted. Furthermore, the TPPs will require additional transmission space to discharge their ESS energy as their supply obligations are locked in at the system level. Furthermore, cost dynamics of discharging this energy from units will have to be billed separately and require an independent framework.

Beyond this, the consumers currently bear shadow costs of roughly **Rs 5,982.74 crore**, alongside approximately **7.91 million tonnes of avoidable CO₂ emissions**, arising from unused renewable generation and fossil replacement. Storage tied to thermal dispatch does not directly mitigate these curtailment dynamics and therefore cannot substitute for system-level solutions aimed at renewable integration.

8

WHY FLEX MATTERS: SYSTEM-LEVEL FUTURE SCENARIO ASSESSMENT

Integrating flexibilisation can unlock nearly 125.1 TWh of additional annual RE space, allowing 71.5 per cent extra of solar energy relative to FY 2025–26 baselines

Coal flexibilisation can avoid nearly 92–101 million tonnes of CO₂ annually, in thermal fleet emissions even with efficiency penalties

Under flexibilisation, India's grid can create nearly 18,148 MW of additional RE absorption space during high solar hours

Despite addition in India's energy storage capacity, enhancing coal fleet flexibility will remain crucial to long-term grid balancing and avoiding RE curtailment



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8.1 Unlocking Additional RE Headroom: Math Under Flexibilisation

The daily benefit of coal flexibilisation is realised in the system level generation space, flexing of coal fleet creates for RE sources in comparable terms. Currently the 55 per cent MTL across the installed capacity of coal power plants in India have a daily operational ceiling to integrate RE. In case of high-power demand day, wherein non-solar evening peak the operational requirements necessitate the scheduling of entire available capacity. On such days, the fleet then flexes down to its operational limit of 55 MTL, which in the present case is maxed out at 125,684 MW or 125.68 GW, subject to availability of the entire installed capacity.

The enhanced coal fleet flexibilisation creates additional operational space for renewable energy integration by lowering the minimum technical loading of coal-based thermal power plants during solar-rich daytime hours. In operational terms, reducing coal fleet loading from 55 per cent to 40 per cent during 10 daytime hours frees a portion of the generation requirement that can instead be met through renewable energy sources.

To estimate the additional renewable energy accommodation potential, the analysis considered a coal fleet capacity of 228.5 GW operating under a deeper flexibilisation regime. The calculation uses the incremental 15 percentage-point reduction in loading between the existing 55 per cent operational level and the proposed 40 per cent loading level.

Step 1: Total Capacity $\times$ (Current MTL – New MTL) = Additional capacity/
 Δ Capacity

$$228.5 \text{ GW} \times (55 - 40) = \mathbf{34.275 \text{ GW}}$$

Subsequently, the capacity space is further analysed on the unit generation of electricity, as varying sources of RE can be scheduled to meet the space over the solar hours.

Step 2: Additional capacity / Δ Capacity $\times$ Hours of operation = RE space created (GWh)

$$34.275 \times 10 = \mathbf{342.75 \text{ GWh}}$$

The above calculated capacity is maximum range of generation space, especially at the generator level with the presumption of entire coal fleet being on schedule and capable of flexing to the new MTL of 40 per cent.

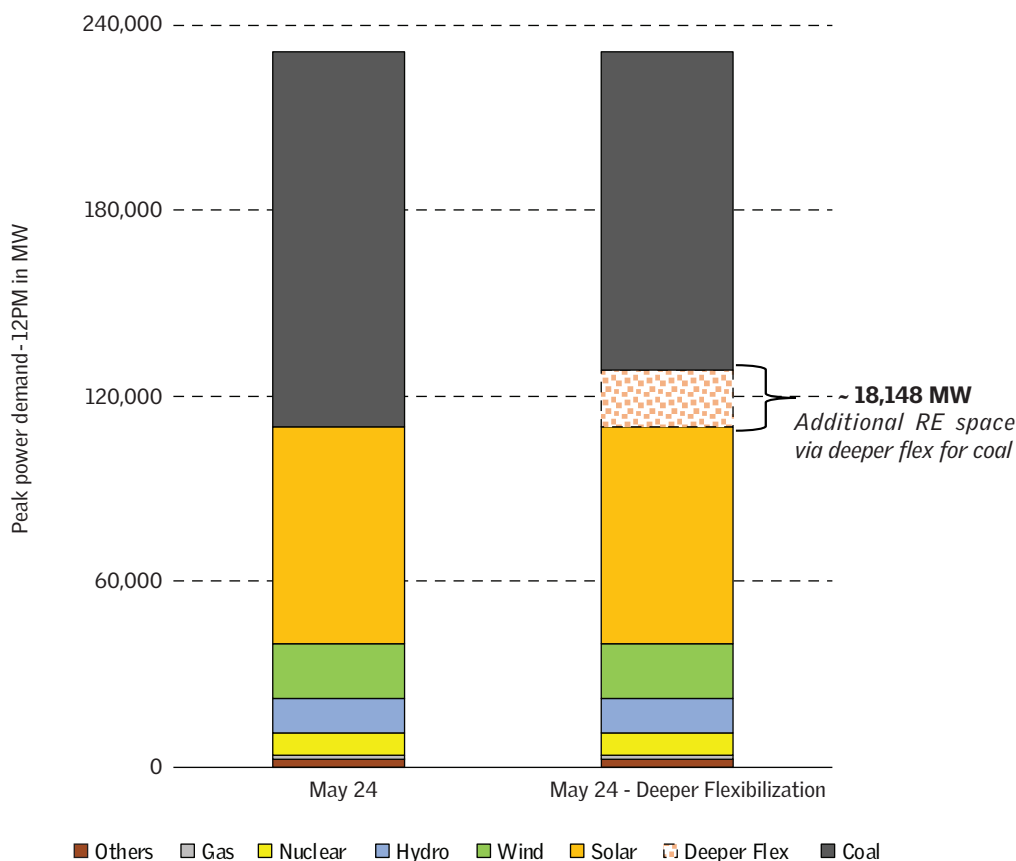
On an annualised basis, this corresponds to nearly **125,103.75 GWh or 125.1 TWh of additional renewable energy** integration potential. The actual net energy delivered into the system would vary depending on the power demand of the day, auxiliary consumption of units on schedule, transmission losses, renewable availability, network congestion, and operational reserve requirements.

On contextual basis, in FY 2025–26, the total solar generation stood at 174.76 TWh, translating into system space for integrating an additional 71.5 per cent of solar energy. Similarly, the total RE generation in the FY 2025–26 stood at 477.79 TWh, thus **additional 26.18 per cent of the annual RE generation** can be integrated into the system.

Reflecting this onto the system on a day-to-day basis, wherein the capacity of coal to flex to a lower MTL creates space for RE, we can analyse the peak power demand position on May 24, 2026. At 12:00 pm, the maximum on system solar capacity was observed to be 70,100 MW and coal at the low of 120,988 MW. Herein, consolidated Demand Met is 227,209 MW. The on-system coal capacity for the day is 187,950 MW and the data reflects it to be at PLF of 64.37 per cent. Assuming 9 per cent auxiliary consumption plus transmission losses, the coal capacity is flexing to its lowest threshold of the day. The assessment uses a net-to-grid basis by incorporating auxiliary consumption within the scheduled thermal generation, thereby representing the actual power injected into the grid rather than gross generator-side output. The difference between the two operating levels represents the additional grid absorption space created for renewable energy integration. The generator-side output at PLF of 40 per cent will showcase a greater degree of space, however that will not be closer to the operational methods of the real world.

The incremental reduction in coal-based generation is then translated into equivalent renewable energy accommodation potential in terms of additional renewable generation with indicative solar and wind capacity equivalence. CSE analysis (see *Graph 39: Source-Wise Generation Mix: Actual Operation Vs Deeper Coal Flexibilisation Scenario (May 24, 2026)*) showcases that flexing coal will create an additional space of **~18,148 MW**. This translates into approximately doubling the wind generation or accommodating 25 per cent more solar generation in the given time period.

Graph 39: Source-Wise Generation Mix: Actual Operation Vs Deeper Coal Flexibilisation Scenario (May 24, 2026)



Source: CSE analysis of GRID India's Daily PSP Report, May 24, 2026

Overall, implementation of flexibilisation for the coal-based thermal power fleet creates a greater space for RE integration on a daily basis. This is a net benefit on the system wherein a significant headroom is created without losing the ability to meet peak power demand.

8.2 The Carbon Payoff: Flexibilisation's Net Decarbonisation Gains

Flexibilisation of coal-based thermal power plants is a systemic saving on CO₂ emissions as it creates greater space for RE to fill in the generation requirement. The reduced usage of coal-based TPPs by operating at lower MTL during day-time results in a net reduction in emissions by lower generation output requiring lower coal intake. To assess the emissions reduction potential associated with coal flexibilisation for renewable energy integration, an indicative fleet-level analysis was undertaken using operational and emissions data for India's coal-based

thermal fleet. The assessment uses the CEA's CO₂ Baseline Database, version 21 released in December 2025. Based on the database, total operational coal fleet of 581 units with an installed capacity of 216.1 GW has been considered. This excludes units with zero generation in the year. During FY 2024–25, the annual average Plant Load Factor (PLF) of the fleet stood at 69.45 per cent and produced nearly 1,363.9 TWh of electricity.

Based on the annual generation and reported emissions, the average fleet-wide emission factor was estimated at approximately 1.04 tCO₂/MWh, corresponding to total annual emissions of nearly 1.2 billion tonnes of CO₂. To evaluate the potential benefits of enhanced flexibilisation, a counterfactual operational scenario was considered wherein the same fleet operates at 40 per cent load instead of 55 per cent during 10 solar-rich daytime hours. Herein, as we are estimating the avoided emissions, it is the gap between the existing MTL and the presumed MTL. (55 per cent – 40 per cent = 15) The avoided coal generation and emissions under this scenario was estimated by applying the steps stated below. The calculation uses the incremental 15 percentage-point reduction in fleet loading across the total available coal capacity.

Step 1: *Capacity × PLF × Time = Generation*

$$216,128.5 \text{ MW} \times 15 \text{ per cent} \times 10 \text{ hours} = 324192.75 \text{ MWh} / \textbf{324.19}$$

GWh

Step 2: *Generation × Emission Factor = Emissions*

$$324192.75 \text{ MWh} \times 1.04 \text{ tCO}_2/\text{MWh} = \sim \textbf{0.337 million tonnes CO}_2/\text{day}$$

OR

$$\sim 337,160 \text{ tonnes CO}_2 \text{ avoided per day}$$

Annualised savings:

$$\textbf{123.06 million tonnes CO}_2/\text{year avoided OR}$$

$$123.06 / 1205.16 \times 100 = \sim \textbf{10.21 per cent of actual annual emissions}$$

(FY 2024-25)

However, operation at lower loading levels is associated with efficiency penalties, including deterioration in heat rate, increased auxiliary consumption, and sub-optimal combustion performance. Using the CEA's estimation of efficiency reduction in performance of TPPs, the range is between 18–25 per cent across technologies and unit capacity sizes. To account for these operational realities, the gross avoided emissions were adjusted downward to reflect the efficiency loss associated with sustained deep turndown operation.

Adjusting the emission factor to account for heat rate/performance loss:

- » For 18 per cent degradation: 1.2272 tCO₂/MWh
- » For 25 per cent degradation: 1.30 tCO₂/MWh

However, for avoided emissions, the key is the **net benefit** from reducing generation minus the efficiency penalty. A practical approximation is:

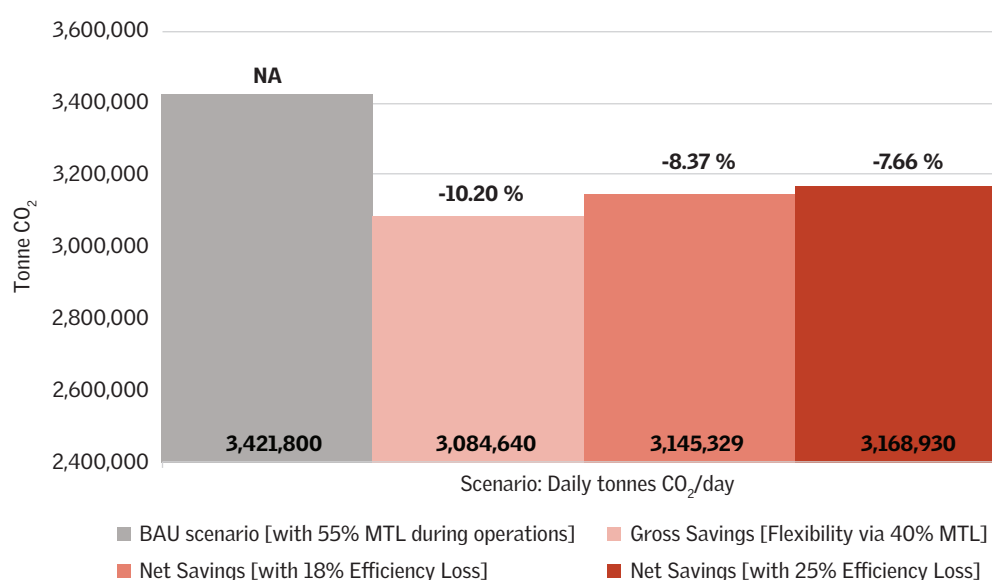
Step: $Net\ CO_2\ savings = Original\ savings \times (1 - Penalty)$

The revised annual CO₂ savings based on adjusted emission factor range:

- » Assuming 18 per cent efficiency penalty: **~100.9 MtCO₂/year** OR
 $100.91/1205.16 \times 100 = \text{~8.37 per cent}$ of actual annual emissions (FY 2024-25)
- » Assuming 25 per cent efficiency penalty: **~92.3 MtCO₂/year** OR
 $92.30/1205.16 \times 100 = \text{~7.66 per cent}$ of actual annual emissions (FY 2024-25)

The avoided generation yielded an indicative emissions reduction potential of approximately **337 thousand tonnes of CO₂ per day**, equivalent to nearly 123 million tonnes of CO₂ annually if sustained throughout the year. This corresponds

Graph 40: Daily CO₂ Saving Potential Owing to Deeper MTL



Source: CSE analysis

to roughly **10.2 per cent of the fleet's current annual emissions**. After incorporating the degradation factor, the net emissions reduction potential from coal flexibilisation remains significant and is estimated between approximately **92–101 million tonnes of CO₂ annually**, equivalent to **nearly 7.7–8.4 per cent of current annual emissions**.

For a greater granular understanding, CSE has analysed the daily CO₂ emissions wherein the fleet operates with a 55 per cent MTL while flexing during daytime operations. Furthermore, CSE has extended the analysis undertaken above and a daily operation scenario is created with gross savings via 40 per cent MTL during day-time operations along with adjusting daily assessment with 18 and 25 per cent efficiency loss and reflected the daily operational emissions subsequently.

Despite the efficiency penalties, the analysis demonstrates that deeper coal flexibilisation can still deliver substantial system-wide emissions benefits while integrating increasing shares of variable renewable energy into the grid. The actual savings will be in the range provided above, yet proving beyond reasonable doubt that flexibilisation allows for net gain in terms of decarbonisation for the power sector.

8.3 Stress Testing Grid: A Capacity Assessment (2027–36)

The gap of non-integration of flexibilisation of coal-based thermal power can be gauged from stress testing the power grid's ability to integrate rising RE capacity alongside inflexible coal. In here, CSE has utilised the capacity forecast of CEA alongside peak demand to highlight the need of flexibilisation to avoid risk to grid and reduce RE curtailment going ahead. In March 2026, CEA released Long-Term National Resource Adequacy Plan (2026–27 to 2035–36), producing the planned capacity addition along with Peak Demand estimate for each coming year. The same is reproduced in the Graph 40, as this is the foundation of the assessment subsequently in the chapter.

While the CEA has undertaken a detailed Resource Adequacy Framework (RAF) assessment, for the current research, the aim is to showcase requirement of flexibilisation at the system level and expose the stark structural paradox facing the conventional generation fleet.

Methodological Framework

The method adopts a targeted **deterministic hourly stress framework** anchored exclusively to annual Peak Demand conditions. *Firstly*, in utility planning and

Table 17: Peak Demand and Installed Capacity (2026–27 to 2035–36)

Year	Peak Demand [in GW]	Installed Capacity [in GW]								Storage [in GW]		
		Coal (including Lignite)	Gas	Nuclear	Large Hydro	Solar	Wind	Other RE	Total	BESS	PSP	Total
2026-27*	270	237	20	10	48	176	63	17	571	6	5	11
2027-28	289	239	20	12	54	214	73	17	629	12	7	19
2028-29	305	245	20	12	55	254	83	18	687	17	13	30
2029-30	325	260	20	13	58	285	93	18	747	24	23	47
2030-31	345	276	20	14	59	320	103	19	811	28	32	60
2031-32	364	291	20	16	61	356	113	20	877	37	44	81
2032-33	388	299	20	19	64	395	123	20	940	46	54	100
2033-34	407	303	20	22	66	434	133	21	999	57	64	121
2034-35	427	307	20	22	75	474	144	21	1063	68	79	147
2035-36	446	315	20	22	78	509	155	22	1121	80	94	174

Source: CEA Long-Term National Resource Adequacy Plan (2026-27 to 2035-36)

*As the current peak has already been attained on May 21, 2026 while capacity has not reached the given level, this FY has not been considered for scenario assessment

regulatory governance, the formal RAF for determining required installed capacity relies strictly on a system’s ability to clear peak demand thresholds while maintaining a secure planning reserve margin. Testing the grid at its absolute peaks aligns directly with how standard capacity expansion mandates are enforced. *Secondly*, peak electricity demand in India heavily coincides with extreme summer heatwaves. This structural reality was reaffirmed recently as peak demand touched **270 GW on May 21, 2026**, when a severe nationwide heatwave pushed the power grid to consecutive historic highs, culminating in an all-time record peak demand. This early-summer spike proves projections and demonstrates that peak load conditions are not anomalies.

Importantly, summer conditions directly coincide with days of maximum solar generation across the country. The framework serves a dual purpose as by evaluating system capabilities under absolute peak conditions, it establishes a baseline that implicitly showcases an even deeper operational crisis on **lower-demand days**. If the conventional fleet exhibits structural inflexibility during periods of high demand, then off-peak or lower-demand months will amplify system limits. Mitigation on such occasions will require lower capacity scheduling, baseline

over-generation, resulting in steeper thermal ramp-down, while intensifying the risk of RE curtailment.

Limitations and Assumptions of the Model

As CSE is not attempting to present an alternative RAF, the scenarios aim to explicitly isolate the structural rigidity of the coal fleet, and so this assessment applies deliberate baseline constraints to other conventional assets. **Gas generation is modelled entirely as a variable balancing buffer** and hence, no fixed, rigid capacity contribution is assigned to it in the data stack. Furthermore, for **Hydro and Wind, the model utilises a conservative, flat average constant** across all scenario columns. While in real-world grid operations wind and hydro exhibit distinct diurnal variation and evening ramping profiles, holding them constant ensures that the resulting operational stress and ramping metrics are transferred purely to the thermal fleet. Furthermore, **ESS and PSP are modelled strictly based on their peak instantaneous charging** and discharging power capacity (in GWs), as this is a future capacity and their operational profile is largely unknown. On **Solar energy**, the model presumes high generation days, based on the pattern observed in FY 2025–26, wherein High demand days coincided with high solar generation days.

The lack of historic data on generation side, limits the capacity of the model and thus not being commensurate towards electricity generation requirement. Therefore, it ignores the generation variation owing to weather conditions on a day-to-day basis. The study's focus being on rigidity of thermal fleet on the system load at large, it cannot be the basis for generation assessment at the system level. Owing to the same, the operational side of thermal units, their auxiliary consumption is not reflected in the scenario and will depend upon the actual generation of the given day. Thus, the actual generation profile of units will be higher than observed in the model owing to their own operational consumption.

Furthermore, the model has maintained a uniform reserve margin of 10 per cent across all sources of generation. The same is based on inputs taken from regulatory authorities, and the CEA documents on RAF.

Peak Demand Profile

As mentioned above, India attained a new Peak Demand of 270 GW on May 21, 2026 in the 3:30–4:00 pm window. While the peak itself is in late afternoon, two other peaks can be noted during afternoon ramp (11:30 am–12:30 pm) and in the late evening (10:30–11:30 pm). Similarly, even during high demand months, over the weekend the demand is relatively lower. Simultaneously, the India sees high demand during September/October months too, as observed in 2024–25. The peak is relatively lower, while observing higher quantum of solar generation.

Hence, the Peak demand profile is adjusted in this report over three distinct periods, to showcase the adequacy over different loads.

India's peak demand is estimated to grow on an average CAGR of 5.5 to 6 per cent range over the coming decade. CSE has therefore applied this range to the adjusted peak demand profiles. Additionally, the noon squeeze demand is usually 90–93 per cent of the actual peak demand in late afternoon of the particular day, hence the peak profile is for the same is estimated accordingly. Additionally, the noon squeeze demand is identical to the late evening demand during the hot months, and therefore the same demand estimate is applied to it.

The low demand months are 75–85 per cent of the peak demand of the particular year, as observed in CSE's analysis of peak demand over the FY 2025–26. Thus, the low demand peak is estimated in the range of 80–82 per cent of the peak demand of the given FY. The peak demand profiles considered in the models are represented separately in the table below (see *Table 18: Peak Demand Trajectories Over Scenarios (in GW)*).

Table 18: Peak Demand Trajectories Over Scenarios (in GW)

Year	Scenario 1	Scenario 2 & 4	Scenario 3 & 5	Illustrative scenario
	Gross Peak Demand	Gross Noon Peak Demand	Gross Non-Solar Peak Demand	High RE + Low Gross Demand
	(3:30–4:00 pm)	(11:30 am–12:30 pm)	(10:30–11:30 pm)	(3:30–4:00 pm)
2027–28	289	268.77	268.77	236.98
2028–29	305	283.65	283.65	250.10
2029–30	325	302.25	302.25	266.50
2030–31	345	320.85	320.85	282.90
2031–32	364	338.52	338.52	298.48
2032–33	388	360.84	360.84	318.16
2033–34	407	378.51	378.51	333.74
2034–35	427	397.11	397.11	350.14
2035–36	446	414.78	414.78	365.72

Source: CSE analysis of CEA Long-Term National Resource Adequacy Plan (2026-27 to 2035-36)

The assessed scenarios are based on the above-mentioned demand profiles. The High RE with Low Gross Demand profile showcases the need for flexibility in the system, with peak demand being considerably lower than the yearly peak at

the same time of the day. The analysis turns to the scenarios discussed in the next section.

Core Operational Scenarios: CSE Analysis

To capture the distinct balancing challenges across a high-RE grid within a single peak day, this study breaks the diurnal cycle into five time-coincident capacity snapshots:

Reading the Scenario Matrices: The Four-Column Framework

To maintain a uniform analytical standard across all time horizons, each year modelled in the subsequent graphs is visualised using a standardised cluster of four interconnected data columns. Understanding this architectural “Master Key” is essential for interpreting the grid constraints revealed in each scenario:

Column 1 (*Total Available Resources*): Stacks the raw, uncurtailed maximum available capacity of zero-carbon (Solar + Wind + Hydro + Storage + Others) and firm power conventional sources (Coal + Nuclear) against the target demand line to illustrate the pure resource volume available.

Column 2 (*Required capacity*): Stacks the unconstrained RE *on top* of adjusted coal capacity to achieve requisite peak demand, wherein coal fleet is artificially adjusted to meet demand. The box in the column highlights the PLF of the available coal capacity.

Column 3 (*The 55 per cent MTL Constraint Profile*): Stacks the available RE *on top of* the fixed, un-backable thermal baseline required if the coal fleet remains bound to a rigid 55 per cent MTL.

Column 4 (*The 40 per cent MTL Flexibility Profile*): Stacks the exact same renewable energy profile, but on top of a compressed thermal baseline unlocked by retrofitting the coal fleet to a flexible 40 per cent MTL.

Line 1 (*Gross Demand Target*): Represents the baseline system demand for that specific time window. The Purple Line running across the top of the columns tracks the shifting trajectory of assessed peak demand over the decade.

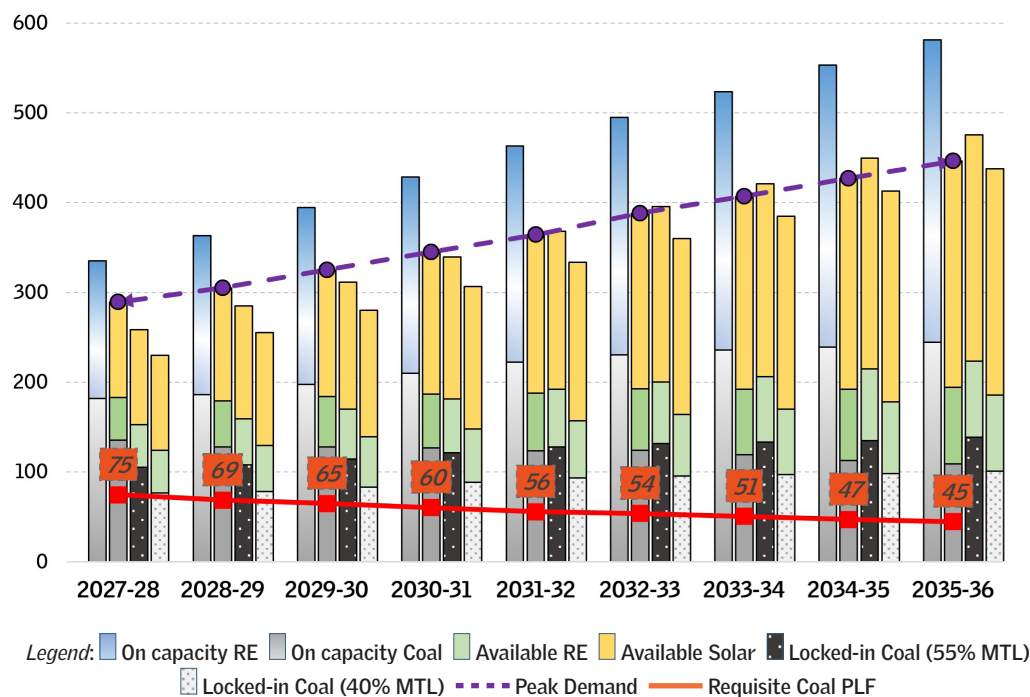
Line 2 (*Coal PLF*): The Red Line cutting across the bottom of the matrices tracks the Requisite PLF (in per cent) of the operating coal fleet, directly measuring the

operational strain or under-utilisation forced upon conventional assets under different balancing regimes.

Scenario 1: Gross Peak Demand Window (3:30–4:00 pm)

India's peak demand usually arrives 3–3.5 hours after the solar capacity peak as heating conditions continue and so this captures the true afternoon gross peak but solar generation has begun its sharp post-noon decay, testing the immediate ramping readiness of the conventional fleet.

Graph 41: Scenario 1: Gross Peak Demand Estimation (3:30–3:45 pm)



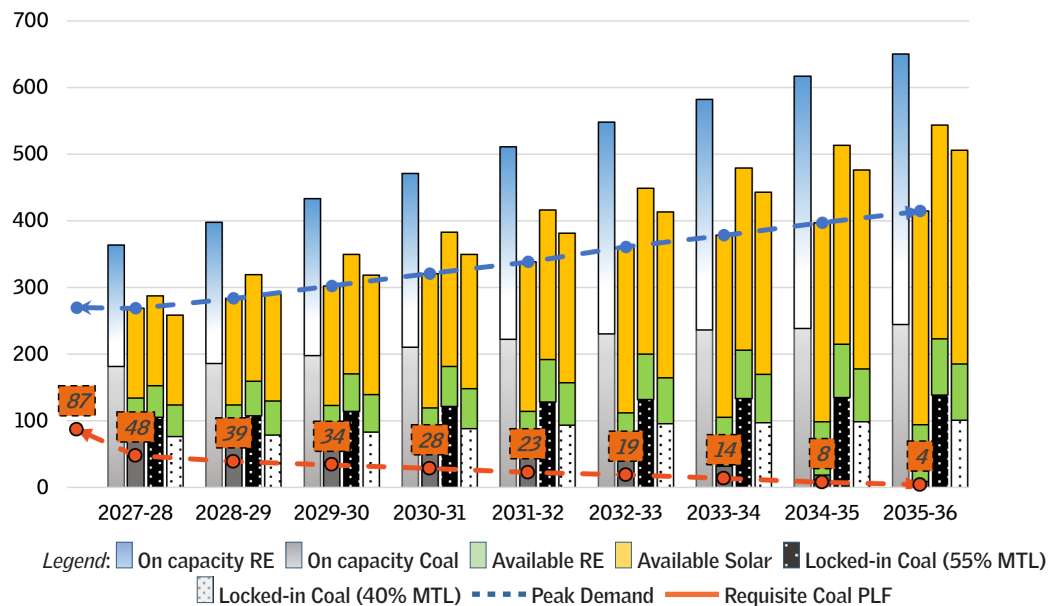
Source: CSE analysis

Analysis: The constant rise in Solar along with other RE sources will necessitate flexibilisation of the coal fleet by the end of the decade in meeting peak demand. The day-time peak demand is squarely within the installed capacity on board, and lack of flexibility will result in large scale curtailment of solar energy.

Scenario 2: Gross Noon Squeeze Window (11:30 am–12:30 pm)

The Afternoon peak demand is in a rising state whereas, maximum solar generation happens in this window with aim to evaluate whether the un-backable MTL of the legacy coal fleet forces a supply overflow and clean energy curtailment (see *Graph 42*).

Graph 42: Scenario 2: Gross Noon Squeeze Demand Estimation (11:30 am–12:30 pm)



Source: CSE analysis

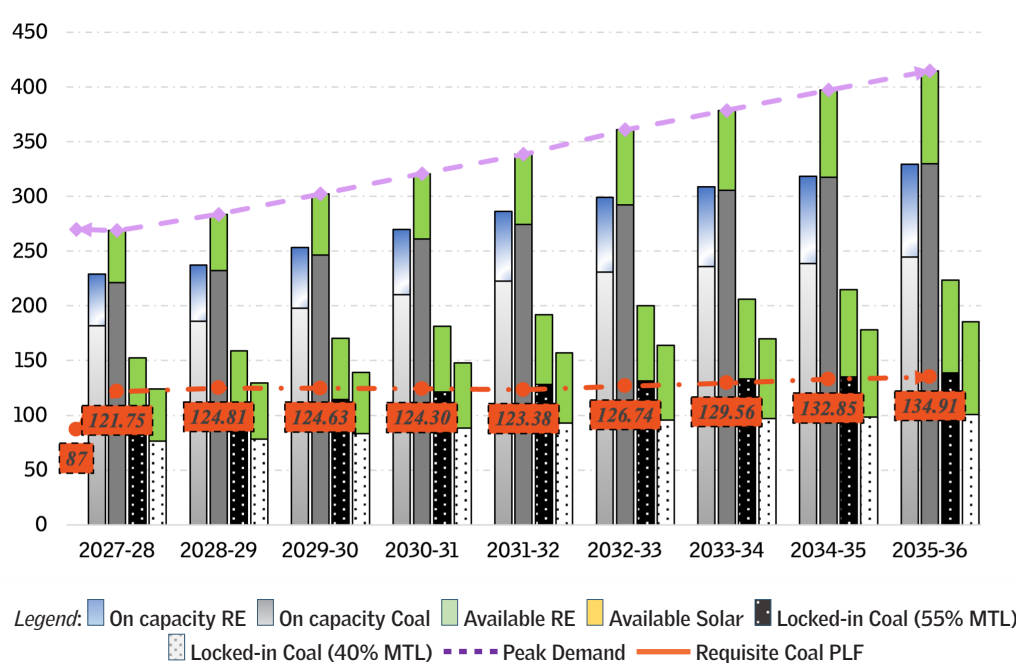
Analysis: The afternoon squeeze in demand establishes the need for ramping within the system for conventional sources, as high solar penetration showcases immediate necessity of coal power ramp. The inflexibility of expanding thermal fleet to a rigid 55 per cent MTL over-allocates baseload to fossil fuel sources, forcing a supply overflow that makes clean energy curtailment structurally inevitable. Furthermore, it highlights the growing space for storage at solar to balance operations of different sources.

Scenario 3: Gross Non-Solar Peak Demand Window (10:30–11:30 pm)

Year 2026 has showcased that the late-night domestic cooling need results in a high demand that is coincidental to afternoon demand profile. This assessment highlights that the demand surge with solar energy dropping to zero, exposes the grid's raw reliance on dispatchable capacity and measuring the extreme PLF stress imposed on conventional units (see *Graph 43*).

Analysis: Driven by late-night cooling needs, the non-solar peak demand tracks identically to midday metrics. With solar generation at zero, the entire burden drops onto dispatchable units, creating extreme PLF stress across the conventional fleet. Herein, lies the need of creating RE buffer via storage alongside the need

Graph 43: Scenario 3: Gross Non-Solar Demand Estimation (10:30–11:30 pm)



Source: CSE analysis

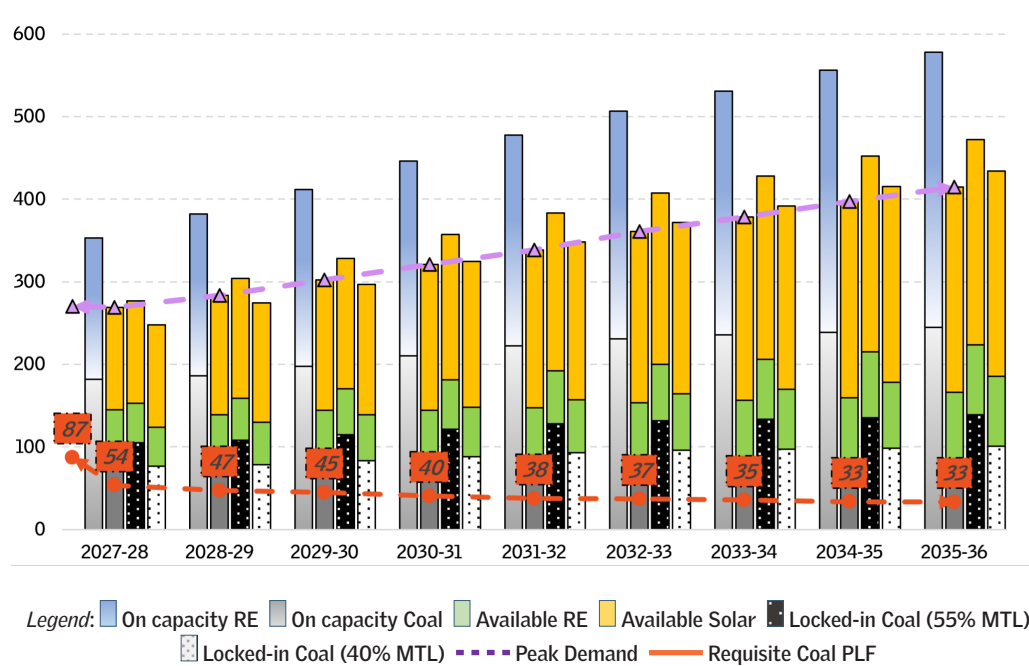
to mitigate night time peak with demand flexibility measures in the long run. With Gas supply erratic and expensive, reliance on RE backed storage alongside ramping space of coal are the long-term solution.

The analysis of future power supply cannot be without the integration of storage in the form of ESS and Pumped Storage (PSP). The ESS adds to the afternoon peak load as it needs power to charge itself, while adding to dispatchable power source during non-solar hours. PSP is self-sustainable and has been utilised during non-solar hours for meeting power demand. Currently, India's tendered ESS are aimed at short two-to-four-hour storage, meaning a maximum of two cycles within a day. As this is a future case, for CSE assessment, the presumption has been to integrate a single cycle storage that is charged with solar energy during day time. Furthermore, the discharge has been reserved for non-solar operations.

Scenario 4: Gross Noon Squeeze Demand Window with Storage Integration (3:30–4:00 pm)

Herein, revaluation of gross afternoon squeeze of peak demand with solar energy being deployed partially to charge the planned ESS fleet, to assess thermal ramping stress mitigation with storage diverting RE for charging (see *Graph 44*).

Graph 44: Scenario 4: Gross Noon Squeeze Demand Estimation with Storage on System (11:30 am–12:30 pm)



Source: CSE analysis

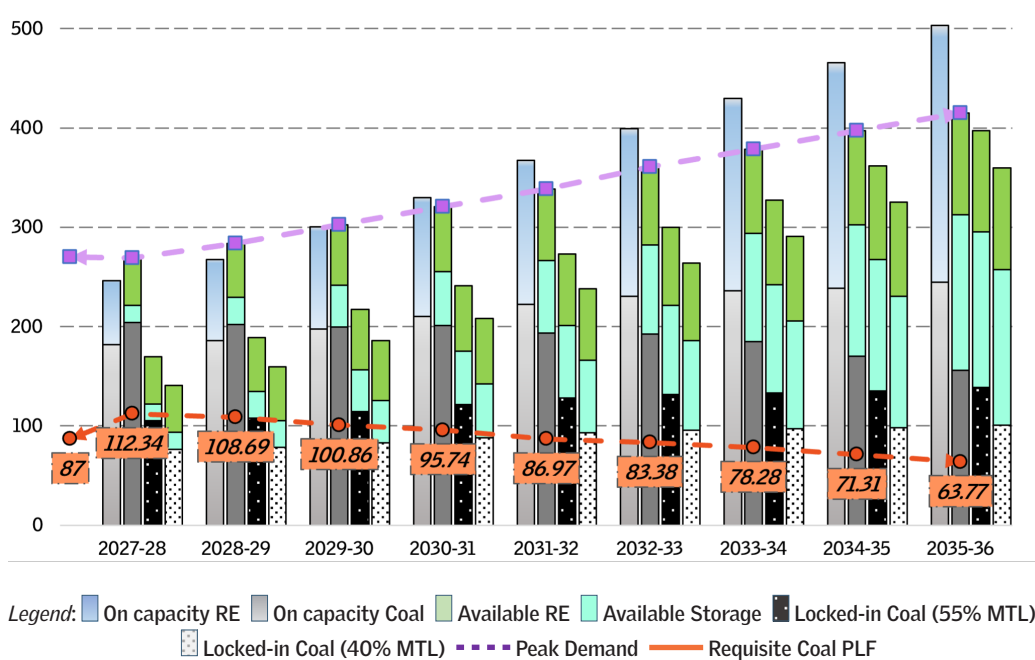
Analysis: Integrating a projected storage portfolio that scales from 19 GW to 174 GW by 2035–36 provides a critical midday charging sink for excess solar generation. Furthermore, it aids the thermal ramping need and mitigates the severe ramping strain imposed on thermal units during the sunset transition. Yet, the need for flexibilisation seems obvious with storage too, as with subsequent year the requisite PLF of coal fleet continues to fall.

Scenario 5: Gross Non-Solar Peak Demand Window with Storage Integration (10:30–11:30 pm)

Within this, the late-night peak is modelled with storage support, mapping the capacity of the ESS and PSP portfolio to discharge over sustained evening hours to shave the nighttime peak demand and assess the need of conventional fleet to meet demand (see *Graph 45*).

Analysis: The sustained evening storage injection of BESS and PSP directly reduces raw system reliance on conventional capacity, capping extreme nighttime thermal PLF peaks. The rising RE capacity during non-solar hours showcases

Graph 45: Scenario 5: Gross Non-Solar Demand with Storage on System (10:30–11:30 pm)



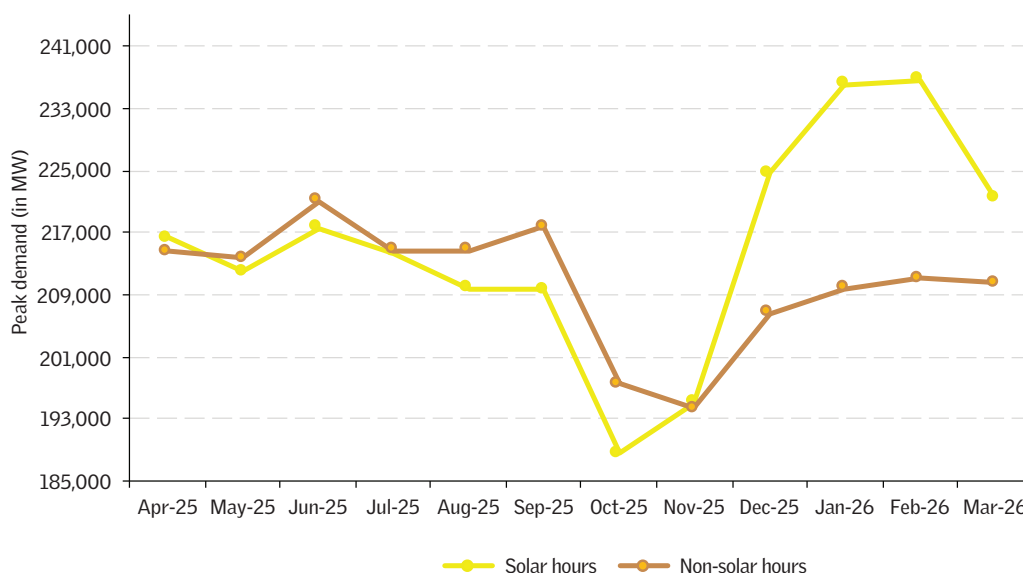
Source: CSE analysis

the case for flexibilisation of coal, especially because the scenario estimates the peak non-solar demand whereas the actual demand will be lower on most days of the year.

Average Peak Demand Analysis: FY 2025–26

To ensure that future models are grounded in real-world facts, an examination of the actual monthly peak demand from FY 2025–26 was incorporated and averaged across all months. While the main scenarios consider extreme weather days, the historical data from GRID India’s Daily PSP Reports over one year shows how the grid behaves on a regular, month-to-month basis across solar and non-solar hours. Interestingly, FY 2025–26 was a low-demand year because unusual summer rains kept temperatures down. This baseline proves that even when weather anomalies depress absolute summer peaks, the underlying structural challenges of grid balancing remain persistently active across the entire seasonal cycle.

The Average Peak Demand data in *Graph 46* makes a clear case that coal plants need to be flexible all year round. Even with the unusual summer rains, the numbers show that the non-solar evening peak was actually higher than the daytime solar peak in five different months (June through October 2025). This proves that the

Graph 46: Average Monthly Peak Demand: Solar Hours and Non-Solar Hours

Source: CSE Analysis of GRID India's Daily PSP Report [FY 2025–26]

need for fast ramping after sunset is far greater than people think. Additionally, during the hot months of April and May 2025, the tight gap between daytime and nighttime peaks shows that the minimum running capacity of coal plants must be lowered during the day to leave enough room for solar energy. Additionally, this shows that India's power demand stays relatively high and steady all year, dropping only slightly during winters. The heating climate reduces the impact of winter onto power demand over the season. Thus, flexibility is not just a summer requirement, it is a 365-day necessity to prevent RE curtailment and reduce system costs of electricity generation low.

8.4 Strategic Conclusion: Beyond Capacity Expansion

The collective insights across scenarios confirm that grid balance cannot be sustained through capacity addition alone and structural flexibilisation of the grid including coal fleet is a growing necessity. As the energy transition sharpens, the ramping needs of the grid become starkly obvious, particularly during the sunset window when the system must adjust to decaying solar generation while gross cooling loads remain highly elevated. *Crucially*, while this assessment models absolute peak conditions, actual daily peaks throughout most of the year will sit significantly lower.

Compounded by a warming climate that triggers unpredictable demand surges, alongside erratic weather patterns such as untimely rainfall that abruptly drop solar output or lower regional demand, the necessity for deep operational flexibility in coal becomes paramount to absorb sudden generation volatility without risking grid instability. By enabling the coal fleet to compress its minimum technical floor down to 40 per cent or lower, the system unlocks vital headroom that integrates greater renewable energy. This flexible operational paradigm directly creates a secure, low-risk ecosystem for a significantly greater volume of future renewable energy capacity additions.

This operational shift is backed by substantial, system-wide capacity and environmental payoffs. Moving the coal fleet from a 55 per cent to a 40 per cent MTL over 10 daytime hours unlocks an additional annualised grid absorption space of ***nearly 125.1 TWh***, effectively creating room to integrate an additional 71.5 per cent of solar energy or 26.18 per cent of total RE relative to FY 2025–26 baselines. While factoring in a steep 18 to 25 per cent thermal efficiency degradation penalty, the flexing framework delivers a net climate dividend by avoiding between 92 and 101 million tonnes of CO₂ emissions annually, equivalent to **7.66 to 8.37** per cent reduction in the fleet's total annual carbon footprint.

Ultimately, can help in safeguarding grid security as well as RE integration while being cost effective to the end consumer. It prevents investments into new coal assets preventing the risk of stranded assets. Additionally, this maximises the integration of RE generation and allows the pairing of the same with energy storage. The analysis highlights the need of implementing the existing policy mandate of compressing coal-based thermal MTL and raising ramping capacity. This aids in maximising RE use during the day time hours.

9

FINDINGS OF THE REPORT



The report highlights several key findings that underscore the growing need for flexibilisation in coal-based thermal power plants. They reveal the emerging systemic, structural, and policy gaps within the regulatory ecosystem that has strained the implementation of flexible operations across India. They establish flexible operation as an operational necessity of the country's evolving power system, not merely a technical option.

- I. **Daytime solar penetration is rising:** India's installed solar capacity has grown by **90 GW** over the past six years, with non-fossil fuel capacity now surpassing fossil-based capacity. This has led to a sharp rise in daily solar energy penetration, with daytime solar penetration increasing by **67 per cent** since 2020. With 93 GW of solar capacity currently under construction, the system-wide requirement for integration is expected to roughly double in the coming years.
- II. **Power system ramping requirements are rising rapidly:** The widening gap between peak and lean demand, exceeding 70 GW within a day in 2025, has significantly increased system's ramping requirement. Thermal plants must now adjust output more frequently to maintain real-time supply-demand balance, grid frequency and increasing renewable penetration. System-level ramping requirements have already reached about 250 MW per minute and are projected to rise to **380–420 MW per minute** under high renewable penetration scenarios, indicating growing dependence on flexible thermal generation for grid stability.
- III. **Deepening duck curve necessitates lower minimum technical loads for thermal plants:** Rising solar generation is producing sharp midday reductions in net load for thermal plants followed by steep evening ramps. During solar peak hours, thermal units are already operating near their minimum technical load, limiting their ability to reduce generation further. Without lowering MTL thresholds through enhanced flexibility, additional solar output will increasingly be curtailed to maintain grid balance. As solar penetration continues to rise, expanding thermal flexibility by enabling deeper ramp-down capability becomes essential to prevent large-scale daytime renewable curtailment.
- IV. **Grid stability risks due to thermal fleet constraints led to frequency mismatch events:** Recent high-frequency episodes of 4, 11, and 25 August 2024 examined by CERC exposed the grid's limited ability to respond to thermal over-injection, greater RE generation, and sudden fall in

power demand. Current thermal minimum load constraints with fleet limited to 55 per cent MTL drove sustained frequency deviations and has subsequently led to RE curtailment for grid stability management. The events reflected coordination gaps across scheduling, dispatch, and market mechanisms, alongside insufficient downward reserves and limited real-time balancing capability highlighting the structural mismatch between system requirements and thermal operating capability, particularly during solar hours.

- V. **Rising RE curtailment increasing economic and climate burden:** Renewable energy curtailment is increasing, as system flexibility struggles to keep pace with solar expansion. Grid interventions show large episodic curtailment, including 45 GWh on a single day and over 93 GWh during peak stress events. Between April 2025 and March 2026 alone, about **7,136.39 GWh** of solar and **486.99 GWh** of wind generation were curtailed. This led to added economic burden of Rs 2,651.32 crore as shadow cost of unused RE and Rs 3,331.42 crore as the replacement cost of fossil fuels, resulting in a total economic burden of **Rs 5,982.74 crore in 2025–26**. Additionally, this resulted in **approximately 7.91 MT of avoidable CO₂ emissions**. These growing volumes reflect structural limits in capability, reserve provisioning, and storage availability, underscoring the urgent need for enhanced thermal flexibility.
- VI. **Thermal Flexibility Unlocks Multi-Gigawatt Space for Immediate RE Integration:** Compressing the MTL of India's coal fleet from 55 per cent to 40 per cent during 10 solar-rich daytime hours creates an immediate, system-wide operational headroom of **34.275 GW**. On a day-to-day operational level (as modelled on a typical peak demand day), this deep-flexing framework creates approximately **18,148 MW of additional real-time grid absorption space**. This structural capacity relief effectively allows the grid to accommodate 25 per cent more solar generation or completely double its wind integration during critical midday windows without risking baseload over-generation.
- VII. **Deep Turndown Operation Yields Net Decarbonisation Gains Despite Fleet Efficiency Penalties:** Sustained low-load thermal operations trigger significant heat rate deterioration, increased auxiliary consumption, and sub-optimal combustion performance, resulting in a technology-wide efficiency penalty ranging between 18 per cent and 25 per cent. However, the counter-factual modelling proves beyond reasonable doubt that the

clean energy replacement benefit vastly outpaces these performance losses. Lowering the fleet's operating floor to 40 per cent delivers a net annual environmental dividend, avoiding **between 92 and 101 million tonnes of CO₂ emissions**. Thus, creating a *net fleet carbon footprint reduction of 7.66 per cent to 8.37 per cent on a daily basis*.

- VIII. Rapid Battery and Pumped Storage Scaling Cannot Substitute for Long-Term Fleet Flexibilisation:** While integrating a massive, projected national energy storage portfolio (scaling from 19 GW in 2027–28 to 174 GW by 2035–36) provides an essential midday charging sink and mitigates severe evening ramping strains, it does not solve the structural rigidity of the conventional fleet. Because massive solar capacity additions continue to depress the required daytime PLF of coal year-over-year, RE curtailment remains structurally inevitable if the legacy fleet stays bound to a rigid 55 per cent MTL baseline. Storage expansion and aggressive thermal floor compression must be mandated in tandem to achieve permanent grid balance.
- IX. Costly gas is bridging peak demand surges:** India's evening demand surges, coinciding with rapid solar decline, are increasingly met by gas-based generation due to limited ramping capability in coal plants. For instance, assessment of demand on April 23, 2025 highlights a rise in demand from 213 GW to over 224 GW within an hour, while solar output collapsed from nearly 19.4 GW to under .3 GW. With coal ramping constrained, gas generation increased by 6–8 per cent in each 15-minute block despite high costs of Rs 12–12.57 per kWh, reflecting the system cost of inadequate thermal flexibility. Therefore, these demand surges are being met with double economic outlay than coal or RE to provide for required power demand.
- X. Pilot studies confirm technical feasibility for flexibilisation:** CEA's pilot flexibilisation studies have demonstrated capability of Indian coal units to operate flexibly. Majority pilot units achieved the 40 per cent minimum load target and DVC's Andal unit operating even lower. Ramp rate tests confirmed performance ranging from baseline 1 per cent per minute to over 3 per cent per minute in select units. These results provide empirical evidence of technical feasibility while underscoring the need for targeted retrofits and unit-specific operational modifications.

- XI. Tariff recognition of flexibility costs remains partial:** Flexible operations have financial implications requiring CAPEX and continuous operational costs impacting equipment life. The CERC has recognised the same via separate regulatory framework, yet significant gaps in elemental coverage remain limited resulting in ineffective implementation. The CERC mechanism allows recovery of CAPEX via consumer pass-through, along with selected operational impacts such as heat rate degradation and additional secondary fuel consumption. However, **lifecycle impact costs on plant equipment are not covered**, largely due to the difficulty of attributing future damage, specifically to flexible operations rather than routine operational issues. In addition, several transition-related expenses, including workforce upskilling, testing and commissioning, enhanced grid and scheduling coordination, and broader system integration requirements, remain outside existing compensation frameworks. Moreover, tariff mechanisms typically rely on **averaged operational parameters**, which may not fully capture the real-time costs associated with flexible plant operation.
- XII. Regulatory gaps and centre-state misalignment slows flexibilisation:** The current regulatory framework creates uneven incentives across different categories of power plants. Flexibility compensation currently applies primarily to cost-plus generating stations, while competitively bid plants generally lack comparable cost recovery mechanisms despite being subject to similar operational requirements. Regulatory approaches also vary widely across states, with some regulators relying on simplified norms or state-specific methodologies rather than standardised, formula-based compensation mechanisms. Adoption of flexibilisation regulations remains uneven; only five states have issued formal provisions recognising flexibilisation costs cover leading to significant non-coverage of the coal fleet. This regulatory asymmetry leaves a large portion of the coal fleet without adequate policy support, creating uncertainty for plant operators and slowing the broader adoption of flexible generation practices.
- XIII. China showcases ambition and policy enforcement of a far steeper scale:** China has successfully transitioned their 1.1 TW coal fleet beyond baseload operation, allowing their power generation mix to contain 50 per cent RE. Having started similarly to India in 2016, their target for flexible operation is to operate the fleet at technical loads of 25 per cent. Post 2021, with a decisive national push, they have transitioned over 300

GW of coal fleet with aggressive retrofits to achieve new minimum load targets. Their current target, updated in 2025, is on course to retrofit their entire coal fleet to operate between 25 to 40 per cent technical load. The rapid execution is driven by binding administrative levers, including performance-contingent PPA renewals on an annual basis. Their model integrates a capacity payment system to aid coal units in their economic viability owing to falling utilisation factor as renewables surge in the power grid. China's model ensures that access to state-directed capital is strictly contingent on retrofit execution, transforming national Five-Year Plan objectives into enforceable investment decisions.

- XIV. BESS not yet scaled for system needs:** As of 2025, India's operational BESS capacity remains limited at 205 MW (0.5 GWh). The sector is primarily focused on short-duration storage (two to four hours) for solar shifting and grid stability, while LDES is currently in the R&D phase. To accelerate growth, in 2025, the Union Ministry of Power approved a VGF scheme for 43.2 GWh of BESS. Currently, India targets to reach 236.22 GWh by 2030 and 1840 GWh by 2047, which will require acceleration and a gestation time looking at the current deployment numbers. The challenge of global supply chain and the need for high capital cost will have to be navigated for accelerating deployment.
- XV. Battery storage at coal plants is prohibitively costlier:** Replacing thermal ramping with battery storage at coal plants would require roughly 30.8 GW/184.7 GWh of battery capacity, implying investment of Rs 3.7–Rs 9.6 lakh crore for long-duration systems or Rs 1.08–1.39 lakh crore even for short-duration deployment. This translates into a per unit fixed cost recovery in the range of Rs 0.8–Rs 7.1 over 15-year period. On a CAPEX level, the expenditure is roughly 600 per cent–31,000 per cent higher than flexibilisation expenditure. Directing investment toward thermal-linked storage risks diverting scarce transition capital away from renewable integration and system optimisation priorities. Also, with limited duration storage capacity, the challenge of constantly fluctuating demand will remain unaddressed.
- XVI. Flexibilisation is a financially moderate:** Cost assessment shows that flexibilising India's 199.4 GW coal fleet requires capital investment of roughly **Rs 2,898–Rs 14,490 crore**, with tariff impacts limited to about **0.47–2.35 paise/kWh** under phased recovery. Even when accounting for operational degradation, system-level cost increases remain incremental

rather than structural, with daily tariff increase remaining between 8–15 per cent. This demonstrates that flexible thermal operation can deliver balancing capability at manageable financial cost within existing tariff frameworks, making it an economically viable near-term instrument for renewable integration.

XVII. Flexibility follows incentives, dispatch control and policy consistency:

Experience from China and Germany shows that thermal flexibility scales when incentives, dispatch rules, and long-term policy direction move in alignment. Binding planning frameworks, consistent policy signalling, and coordinated financial support sustain implementation momentum over time. China enforces it through performance-contingent contract renewals, where non-compliant units lose market access, and discretionary dispatch that rewards flexible units with higher utilisation while Germany leverages market maturity, using 15-minute trading blocks and price-based dispatch to provide clear financial rewards for rapid responsiveness. Together this demonstrates that flexibility adoption depends not only on technical capability but on durable institutional commitment and aligned system-wide incentives.

XVIII. Implementation of India's flexibilisation plan lags behind despite AGC expansion:

Implementation of the phasing plan remains slow relative to regulatory timelines. Of the 513 units (199.4 GW) targeted, only **one unit has fully achieved both** 40 per cent MTL and ramp-rate compliance, with about 1.9 GW demonstrating low-load capability without full ramping validation. Even the pilot phase remains incomplete. In contrast, AGC has scaled to **72.3 GW across 144 units**. This highlights faster progress in grid-level system update than plant-level flexibility related retrofitting.

XIX. Renewable energy currently lacks grid-forming capability:

India's power system continues to rely on conventional thermal plants to provide inertia, voltage regulation, and frequency stabilisation. Most renewable generation is grid-following and cannot independently support system frequency or provide rapid stabilisation during disturbances. Until grid-forming inverters or large-scale battery energy storage systems are deployed at scale, this gap in frequency-support capability will persist.

10

KEY CHALLENGES



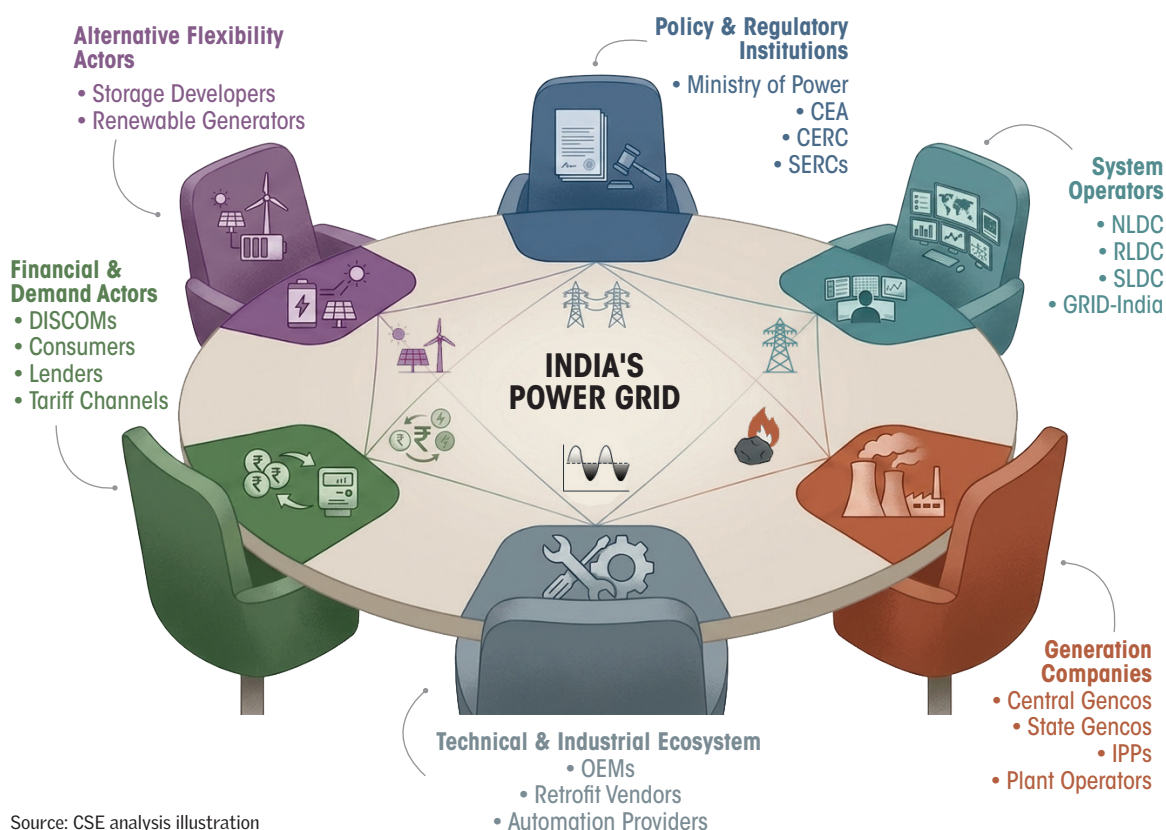
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Flexibilisation of coal-based thermal generation in India is not constrained by a singular technical or regulatory limitation. Rather, as demonstrated across the preceding chapters, its implementation is shaped by the intersection of engineering capability, operational coordination, tariff economics, institutional alignment, and broader transition strategy choices. The diversity of retrofit requirements across the fleet, dispatch and scheduling complexities arising from renewable variability, evolving tariff compensation mechanisms, and differing regulatory and ownership contexts collectively indicate that barriers to implementation are systemic in nature. Consequently, understanding these constraints requires viewing them not as isolated operational issues but as interacting subject domains embedded within the functioning of the power system.

The stakeholder landscape involved in flexibilisation reflects this systemic character. Responsibilities and incentives are distributed across regulators determining cost recovery frameworks, system operators managing real-time grid balancing, generation utilities undertaking plant-level modifications, industrial suppliers enabling technical retrofits, and consumers ultimately bearing cost impacts.

Figure 12: Stakeholders to Flexibilisation Pathway



Each of these actor influences outcomes through different decision levers, from regulatory design and dispatch behaviour to engineering execution and investment prioritisation, thus making implementation outcomes contingent on coordination rather than unilateral action (see *Figure 12: Stakeholders to flexibilisation pathway*).

Highlighting challenges along core subject areas, while mapping the actors engaged within each, is therefore essential for advancing policy implementation. Such an approach allows the analysis to move beyond descriptive identification of barriers and toward diagnosing where coordination gaps, incentive misalignments, or capacity limitations exist. Structuring the discussion in this manner also enables clearer prioritisation of interventions, as it reveals how technical, economic, and institutional frictions accumulate and interact. The following section accordingly examines these challenges through thematic lenses, identifying the principal actors involved in each domain and assessing how their interactions shape the practical trajectory of flexibilisation within India's evolving power system.

10.1 Technical and Engineering Barriers

- **Heterogeneous fleet constraints:** Implementation of flexible operation across India's coal-based thermal fleet is shaped by a range of plant-level technical and engineering limitations that arise from the design characteristics and operational history of existing units, along with the skill set available at units to implement the new requirements. India's fleet is heterogeneous in size, age, and configuration, which creates uneven technical readiness for low-load and rapid-ramping operation. For context, the existing fleet spans 31 different unit sizes, and the oldest units have been in operation for nearly five decades (48–50 years). The intrinsic heterogeneity makes the capability vary substantially across units and impacts the capacity of holding low MTL and ramp on a regular basis. The technical challenge is further intensified by the vintage diversity of the fleet. Units commissioned across different decades embody varying technological standards, control philosophies, and retrofit compatibility, making uniform implementation complex. These design constraints create engineering variability in implementation outcomes and constrain economies of scale by necessitating bespoke, unit-specific solutions.

- **Fuel quality gaps:** Fuel characteristics further complicate operational flexibility. The high ash content associated with domestic coal introduces additional stress on boiler and auxiliary systems under cycling and low-load conditions, amplifying wear on equipment and increasing maintenance sensitivity. Another major challenge is the variability in the quality of fuel supplied across the year to a power plant which adds to the challenge. The current regulations have bypassed the matter of quality fuel supply entirely.

- **Equipment fatigue risks:** Relatedly, regular flexible operation accelerates component fatigue and contributes to incremental life consumption of key machinery, including thermal and mechanical systems, which raises operational risk perceptions among plant operators and influences adoption behaviour. These concerns are compounded by the need for modifications to control and automation systems, as existing instrumentation and legacy control architectures may not be configured to handle frequent load changes or automated dispatch signals. Thus, requiring higher staffing intensity than conventional steady-state running.

- **Workforce capability gaps:** These challenges are further amplified by workforce constraints. Flexible operation, especially during ramping, demands greater manpower and continuous monitoring to identify equipment stress across the unit, yet plant staffing structures and training are typically oriented toward baseload operation. This results in skill gaps in managing transient conditions and interpreting automated dispatch signals, necessitating targeted upskilling and revised staffing approaches, therefore adding another layer of cost and complexity that affects adoption.

Collectively, these factors underscore that flexibilisation is not solely an operational adjustment but an engineering and skill transition, requiring accommodation of design limits, fuel realities, equipment durability considerations, technological diversity across the fleet, and specialised skilling requirements.

10.2 System Operation and Grid Coordination Barriers

Beyond plant-level technical considerations, flexibilisation introduces system operational challenges linked to the coordination of generation behaviour with evolving grid requirements.

- **Altering dispatch requirements:** The increasing penetration of variable renewable energy alters demand–supply dynamics, requiring more frequent load adjustments, reserve management, and responsive dispatch from thermal units. Integrating flexible operation into this environment places additional demands on scheduling and dispatch processes managed by system operators, particularly when balancing renewable intermittency, managing deviations in demand, and maintaining system reliability across regional and state grids.

- **Harmonising variables:** The demand for power supply is variable, necessitating thermal power generation adjustment in accordance with RE generation on a day-to-day basis. The variations in scheduling practices, including over-injection, under-requisition, and differences between declared capacity and scheduled

energy, create complexities in aligning plant operations with dispatch signals. Weather patterns and social events alter it regionally, as seen with the example of Chath Puja in the above chapter. This requires closer synchronisation between generation units and load despatch centres, requiring multiple ramping by thermal units necessitating flexibilisation to harmonise with grid stability.

- ***One grid, diverse landscape:*** Additionally, managing flexibility across multiple jurisdictional layers, national, regional, and state dispatch structures, creates institutional and procedural complexity that can affect consistency in implementation. The variability of micro level climate conditions creates greater fluctuation in the entire system management process.

- ***Lack of schedule:*** A practical operational constraint lies in the limited availability of dispatch schedules for undertaking flexibilisation. Plants require dedicated scheduling windows, transmission headroom to vary injections, and opportunities for test runs to build operator capability. However, scheduling frameworks remain largely geared toward meeting immediate generation commitments, leaving little operational space for experimentation to build up for flexible operations.

- ***New-age tech integration:*** The integration of mechanisms such as AGC and real-time optimisation frameworks further adds layers of operational adjustment that power plants must accommodate, often requiring changes to plant procedures and coordination routines. The AGC is a four-second adjustment mechanism and creates multiple ramping needs, increasing the stress on the generating unit. This flows both ways as the grid manager and plant operator need to keep a constant vigil to maintain stable power supply, increasing workforce requirements.

These challenges highlight that flexibilisation is not only a plant-centric exercise but one that depends on system-wide operational alignment, real-time communication, and adaptive dispatch behaviour across multiple actors within the grid ecosystem.

10.3 Economic and Tariff Alignment Issues

- ***Upfront capital recognition:*** Flexibilisation requires capital expenditure to be committed before operational benefits materialise, and the scale of investment varies across units depending on retrofit needs. This creates uneven financial exposure for utilities, as recovery mechanisms do not always align with the timing or variability of plant-specific implementation requirements. The current system may load debt on utilities and place greater reliance on consumers to meet the same. The CAPEX is a pass through but needs a structured approach with upfront capital for the plan to take off.

- ***O&M and life consumption mismatch:*** Flexible operation increases mechanical stress, component fatigue, and life consumption of equipment, yet these effects are not fully reflected within existing O&M recovery structures. Constant ramping may result in shortened unit life or greater equipment expenditure on a regular basis. The resulting gap between operational wear and tariff recognition creates cost uncertainty for plant operators undertaking flexibility measures. The operator is primarily focused on protecting their machinery, thus unless there is certainty of damage coverage, the gap becomes a risk they are unlikely to take resulting in RE curtailment as the only mitigating pathways.

- ***Averaging damage costs on monthly:*** Current treatment of heat rate degradation and auxiliary consumption relies on averaged parameters that do not reflect unit-specific performance under flexible operation. This approach obscures the operational realities across different unit sizes and vintages, complicating alignment between incurred costs and compensation. The operator may face greater damage that the system cost is not recognising, thus the need for a harmonisation or scope for claim of additional expenses.

- ***Consumer burden allocation:*** Flexibility-related costs ultimately flow through to consumers, making their allocation a system-level consideration rather than a plant-level issue. Balancing cost recovery with tariff stability requires careful calibration to avoid disproportionate impacts on consumers.

- ***Treatment of Section 63 units:*** Generating stations operating under competitive procurement structures face differing pathways for cost pass-through compared to regulated units. The absence of clear mechanisms to address flexibilisation expenditures within these arrangements introduces asymmetry in implementation conditions.

- ***Absence of performance incentives:*** Economic signals currently emphasise cost recovery rather than rewarding operational responsiveness or compliance to flexibilisation norms. Without incentive-linked structures, utilities have limited motivation to exceed minimum requirements or accelerate capability development beyond regulatory obligation. The lack of penalty mechanism for non-compliance reaffirms the need for incentive mechanisms to nudge implementation.

- ***Unfunded pilot and upskilling costs:*** Testing, validation runs, and workforce familiarisation are necessary to transition toward flexible operation, yet these preparatory expenditures are not explicitly accounted for within tariff provisions (neither centre nor state). This leaves utilities to absorb transitional costs outside

formal recovery structures. The limited level of preparatory capital availability with utilities suggests a need for preparatory cost structure like China for gaining implementation momentum.

- ***Uneven regulatory adoption:*** Tariff recognition of flexibilisation remains uneven across jurisdictions (state and centre; even among states), with only select state regulatory commissions formalising coverage. This fragmented landscape produces inconsistent economic signals, affecting implementation pace and investment confidence across the system, as in a single power grid, non-coverage creates unreasonable burden on the complying units and thus reducing incentive for overall adoption.

10.4 Institutional and Regulatory Difficulties

- ***Policy-tariff sequencing gaps:*** Flexibilisation planning and tariff recognition have progressed unevenly across institutional layers of CEA, CERC, and state level ERCs. While the national flexibilisation phasing framework preceded tariff provisions by CERC, adoption at the state regulatory level remains incomplete, leaving a substantial portion of the fleet outside formal recovery structures and creating uneven implementation conditions.

- ***Fragmented curtailment signalling:*** Renewable curtailment costs are experienced across multiple system actors but are compiled and interpreted at an aggregate level. This distribution of impact weakens institutional signalling, making it difficult to translate system-wide inefficiencies into coordinated operational or policy responses.

- ***Absence of guidance for two-shift operation:*** The phasing roadmap identifies ageing units for flexibility roles but does not provide institutional pathways for managing two-shift operation patterns. Without procedural clarity, operational adaptation of older units occurs without structured policy anchoring or coordinated oversight. The current need may require a symbiotic adoption of flexibility alongside two shift operations, yet lack of guidance hampers progress.

- ***Fuel quality oversight gaps:*** Fuel characteristics materially affect flexible operation performance, yet currently fuel quality considerations remain weakly embedded within regulatory and implementation frameworks. As flexibility is adopted, certain mandates at different levels for fuel quality assurance will be needed.

- ***Unassessed adoption of storage:*** Deployment of battery storage at coal facilities has occurred in isolated instances without comprehensive policy-level and

economic evaluation of system implications. Such adoption outside coordinated assessment risks divergence in technology deployment decisions and broader transition objectives.

- ***Emission externalities remain under-integrated in system planning:***

Institutional approaches to flexibilisation and curtailment in the power sector have largely focused on operational efficiency and economic optimisation. Environmental externalities, particularly emissions implications of dispatch and curtailment decisions, remain insufficiently embedded in planning and market signals. This limits the visibility of system-level trade-offs, potentially leading to suboptimal investment and dispatch outcomes from a decarbonisation perspective.

- ***Unrecognised grid capacity development needs:*** Flexibilisation requires continuous capability development among system operators managing evolving dispatch complexity. However, skill development and operational upskilling within grid management institutions are not formally recognised within cost or policy frameworks, leaving coordination capacity implicitly assumed rather than explicitly supported.

10.5 Strategic System Transition Limitations

- ***Setting investment priorities:*** Flexibilisation and alternative flexibility pathways present markedly different investment scales, which must shape our transition choices. While fleet-wide flexibilisation entails capital exposure in the range of Rs 3,078–15,390 crore, storage deployment at thermal sites implies commitments of roughly Rs 1.08–1.39 lakh crore for short-duration configurations and significantly higher under long-duration structures. These disparities should be well understood in the near- and long-term before setting the investment priorities in the sector. Multiple flexibility approaches—including thermal retrofits, storage deployment, and renewable-linked solutions—are advancing without fully integrated strategic coordination. This fragmentation increases the risk of suboptimal sequencing, technology overlap, or investment duplication.

- ***Curtailment-linked system inefficiencies:*** RE curtailment imposes shadow costs exceeding Rs 5,600 crore in 2024–25 alongside avoidable emissions burdens. Persistence of such inefficiencies indicates structural misalignment between generation mix evolution and system absorption capability, complicating transition planning and weakening decarbonisation signals.

- ***Fossil reinforcement:*** Adoption of battery storage at coal facilities shifts storage utilisation toward supporting fossil-linked dispatch rather than enhancing

renewable absorption. This coupling risks reinforcing legacy operational structures and diverting technology deployment away from pathways intended to displace carbon-intensive generation.

- ***Parallel capacity expansion signals:*** The transition environment is characterised by simultaneous renewable expansion, flexible operation mandates, and continued coal capacity planning. These overlapping signals introduce uncertainty in long-term asset utilisation expectations and complicate coherent system evolution toward lower-carbon configurations.

- ***Declining thermal utilisation dynamics:*** Falling plant load factors associated with renewable penetration alter economic and operational assumptions for the thermal fleet. Integrating flexibilisation without sufficient tariff support within this context introduces strategic ambiguity regarding lifecycle investment recovery, future utilisation roles, and system planning consistency.

10.6 Implementation and Execution Barriers

- ***Uneven progress across utilities:*** Implementation of flexibilisation has advanced at differing speeds across generating utilities, reflecting variation in organisational priorities, financial capacity, and operational focus. This uneven progression introduces asymmetry in system readiness and complicates coordinated fleet-wide transition timelines.

- ***Retrofit readiness differences:*** Plant-level preparedness for retrofit activities varies significantly due to differences in equipment condition, technological configuration, and prior modernisation efforts. Such variability limits uniform deployment and necessitates unit-specific implementation pathways, affecting execution consistency. The utilities are unevenly onboard with flexible targets, thus affecting implementation.

- ***Ownership-based variation:*** Divergence in governance structures across central, state, and private ownership categories shapes investment behaviour and operational decision-making. These structural differences result in heterogeneous responses to flexibilisation requirements and uneven adoption momentum. In a unified grid, this variance is blockage that necessitates consensus building.

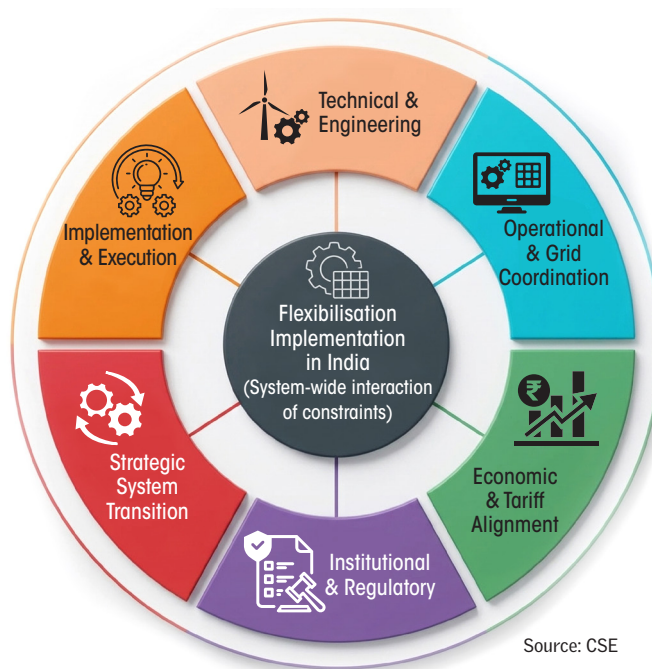
- ***Domestic infrastructure self-sufficiency required:*** Execution outcomes are also shaped by the pace of supporting infrastructure upgrades, including control systems, monitoring tools, and auxiliary plant improvements. Where modernisation lags, operational transition capacity remains constrained, extending

implementation timelines. The quick adoption timescale needs domestic systemic solutions for implementation as paramount for timely achievement while avoiding cost escalations.

10.7 Synthesis of Challenges

Advancing flexibilisation will depend on addressing a set of interrelated constraints spanning plant capability, grid coordination, economic signalling, institutional coherence, strategic alignment, and execution readiness. While each domain presents distinct frictions, their combined effect shapes implementation timelines, investment behaviour, and operational confidence across the system. These challenges also illustrate that flexibilisation extends beyond retrofit execution, requiring alignment between technical practice, market incentives, and regulatory consistency to ensure outcomes that support system responsiveness and renewable integration (see *Figure 13: Challenges to Flexibilisation: A Snapshot*).

Figure 13: Challenges to Flexibilisation: A Snapshot



Rather than treating barriers in isolation, interventions must respond to their cumulative and cross-sectoral character to avoid shifting constraints from one domain to another. The following section therefore translates these identified challenges into targeted recommendations aimed at strengthening coordination, clarifying economic signals, and enabling effective deployment across India's thermal fleet.

11

POLICY RECOMMENDATIONS





India's drive to meet its climate goals while ensuring a reliable energy supply necessitate a transition towards adapting the existing power generation capacity to accommodate greater renewable energy injection. Even though the current scale of RE, is well below the future capacity plan, it is suffering from curtailment on a regular basis. The situation is therefore untenable and requires definite addressal. The report has identified the scale of flexibilisation required for the current coal-based thermal capacity. The stakeholders' role ought to be aligned in conjunction of one another for the necessary uptake of flexibilisation across the current coal fleet. Based on the current status of flexibilisation in 2026 and aligning it with CEA's phasing plan, CSE proposes policy actions for the concerned stakeholders to accelerate the implementation mechanism.

Recommendations for Central Regulators

I. Factors for reconsideration and prioritization in the Phasing plan: The CEA's phasing plan is the bedrock of flexibilisation implementation in India. However, to ensure a functional and cost-effective transition, the current plan ought to reconsider its prioritisation of listed units based on systemic, technical, and economic factors with an evidence-based deliberation. Factors for consideration are:

- *Heat-rate and Emission performance:* While thermal units face an SHR degradation in the range of 18 to 25 per cent during flexible operations, supercritical / ultra-supercritical units maintain a lower baseline emission factor than subcritical units. There is a need to clearly identify the SHR degradation and CO₂ emission during sustained low-load operations in all three technologies, as there is variance in inputs from different stakeholders. Incorporating emission performance and unit degradation into unit prioritisation of the phasing plan will help minimise the overall emission impact, aligning the outcome of flexible operations with larger decarbonisation benefits.
- *Consideration of greater utilisation of efficient and low-emission assets:* Modern ultra-supercritical and supercritical units have been built with high capital expense and are largely under-utilised owing to the rules of Merit Order Dispatch. The rules advantage old subcritical units with lower efficiency, resulting in a slow bleed of the high capital investment into new thermal units. The suggestion is that the phasing plan can incentivise greater utilisation of supercritical and ultra-supercritical units for overall lower systemic emissions.
- *Consideration of two-shift operation for old and inefficient plants:* The cost of retrofitting old and inefficient units / beyond operational life (greater than 30 years of age), will be high, and they may not even have the lifespan left to recover these costs. These units at low-load operations may be at a greater

risk of tripping and thus be an unreliable source of flexibility for the system. These units may be reserved for non-regular usage, during seasonal loads and limited peak meeting support roles or two-shift operations to avoid further capital infusion in their operations.

- *Technological limits of thermal units:* The technology of a thermal unit determines the scale, performance and the cost of retrofitting for flexible operation. For instance, industry inputs state that supercritical and ultra-supercritical units do not possess steam drums and face specific technical constraints around the “Benson point”, necessitating a safety margin of at least five per cent above the MTL during operations. Furthermore, while the O&M tariffs for flexibility consider additional oil consumption, the time variance in start-up is critical to the grid’s planning for power generation. Usually, the start-up time of subcritical units is generally around eight hours, while supercritical / ultra-supercritical units typically require up to 30 hours and incur significantly higher oil consumption. Ignoring the technological constraints of units within the plan will result in a sub-optimal realisation of the system performance of flexible operations, reducing the gains of flexibilization.

CSE recommends that these factors be formally assessed to weigh up and restructure the overall phasing plan. Before a final restructuring is implemented, a detailed evaluation of technological limits, startup economics, and real-time emission profiles is essential for the plan to be functional.

II. Undertake unit health baseline study for life cycle impact costs: Currently, regulators (CERC/SERCs) exclude expected life cycle impact costs from compensation due to ambiguity regarding future wear-and-tear. To resolve this, a structured baseline health assessment should be mandated for all units prior to each implementation phase. Establishing an initial ‘*health signature*’ allows regulators to distinguish between legacy degradation and flexibility-induced damage. The transparency enables evidence-based damage attribution, providing a credible foundation for regulators to authorise the recovery of flexibility-related operational costs.

III.Strategise power system flexibility based on cost competitiveness: CSE’s assessment highlights the significant capital costs associated with deploying BESS at thermal plants, alongside concerns of increased fossil-linked emissions and the potential crowding out of investment from BESS deployment in renewables, especially with the challenge of import dependence and rising global trade curbs. In the current scenario, the higher fixed costs of BESS at thermal vis-à-vis flexibility retrofits, may also show upfront in the already

rising electricity costs thereby increasing the cost burden on end consumers, therefore strategic selection of power flexibility pathways needs to be done based on cost competitiveness as well as increasing clean energy in the grid. The cost dynamic ought to be transparently reflected in the MOD, with scheduling and daily generation determined accordingly. This will enable an evidence-based assessment of cost competitiveness and may reveal BESS's limited viability as a cost-effective system solution relative to flexibility retrofitting.

IV. Integrate flexibility costs into future investment decisions: With renewable energy capacity expanding rapidly and altering the role of coal power, India's future capacity additions ought to be explicitly aligned to the dynamic nature of the power system going ahead. India's rising demand must be met with a least cost generation source. The choice of resource to meet future demand needs to be cost-sensitive. Hence, it needs to be considered that any upcoming coal capacity will have an additional cost of flexibility passed onto the consumers. Inflexible coal investments risk creating underutilised assets and stranded cost burdens due to lower utilisation factors, especially with continuation of long-term PPAs. Policy frameworks should therefore explicitly account for the elemental costs of evolving system needs.

V. Standardise curtailment cost disclosure: Regulatory reporting should incorporate a uniform and transparent accounting of the financial and environmental costs associated with renewable energy curtailment. At present, these impacts remain fragmented across system actors, such as RLDCs and state level DISCOMs, weakening their visibility in planning and dispatch decisions. Establishing standardised disclosure frameworks will improve institutional signalling, enable evidence-based investment prioritisation, and support policy alignment toward reducing system inefficiencies and avoidable emissions. Additionally, the absence of such disclosure frameworks risks obscuring these system-level costs, which are expected to rise with increasing renewable energy penetration, thereby undermining their visibility in planning, investment, and policy decisions.

VI. Operationalise ToD pricing with market-linked dispatch: Power system operations should increasingly align with ToD price signals, enabling dispatch to reflect real-time system value rather than static scheduling. TPPs, particularly for their un-requisitioned capacity, should be allowed to participate in market-based operations akin to captive generators, supplying power during high-price periods, such as peak demand hours or at night when market prices are elevated, creating a competitive operational structure. Participation in this

mechanism will inherently require a unit to be flexible. Embedding ToD pricing within dispatch frameworks will incentivise flexible generation behaviour, and ensure that system costs and efficiencies are transparently reflected in scheduling decisions.

VII. Broaden compensation framework and testing schedules: To accelerate fleet readiness, regulatory frameworks must recognise the full economic and operational costs of the transition to flexibility. This requires incorporating training and testing expenses into CAPEX structures and adjusted fixed-cost tariffs, ensuring these “invisible” costs are recoverable. Simultaneously, system operators under GRID-India, ought to provide designated scheduling windows and transmission headroom specifically for ramp testing and workforce familiarisation. By aligning financial compensation with structured operational allowances, regulators can reduce implementation uncertainty and enable capacity-building without compromising grid stability.

VIII. Establish incentives for complying units: The current policy lacks incentives for generation units to undertake flexibility. As all power units fulfil the basic requirement of energy generation, penalising non-compliance is beyond the core object of the generation unit. Thus, creating incentives, such as preference in MOD and greater generation preference ought to be established into the policy for greater uptake. The Chinese model of lump-sum payouts for complying units can be considered to greatly incentivise the uptake of flexibility by individual generation units.

IX. Fund and strengthen grid system operator capabilities: Flexibilisation significantly increases dispatch complexity, real-time monitoring requirements, and coordination across scheduling layers. Load despatch centres must therefore be aided in adapting their analytical, simulation, and operational capabilities to manage evolving system dynamics. Simulator training programme for operators ought to be pursued. Regulators should recognise investments in workforce training, simulation platforms, and analytical decision-support tools for load despatch centres as eligible system costs, enabling operational capacity to evolve alongside generation flexibility requirements.

X. Inventorise and report fuel quality for flexible operations: Flexible operations require consistent fuel quality, particularly during frequent ramping to balance renewable generation. Variations in coal quality can increase the risk of thermal stress, equipment fatigue, and unit tripping. Regulators ought to require systematic inventorying and transparent disclosure of fuel quality, on a monthly

to weekly basis, by generators and fuel suppliers. Integrating such disclosures within Fuel Supply Agreements and regulatory reporting frameworks will strengthen accountability, improve operational planning, and ensure reliable plant performance under increasingly flexible operating regimes.

XI. Ensure compliance with latest air emission standards under flexible operations: Flexible operations may lead to increased coal consumption and higher emissions of air pollutants due to frequent ramping, start-stop cycles, and part-load inefficiencies. Units must therefore comply with the latest notified emission standards under all operating conditions, including low-load and cycling regimes. In addition, clear operational guidelines and standard operating procedures (SOPs) should be established to manage emissions during flexible operations, supported by robust monitoring and reporting frameworks. This is critical to ensure that flexibilisation does not create unintended public health risks or undermine environmental regulatory objectives.

XII. Reform PPA structures to mitigate litigation risks: Current PPA structures are largely availability-based, with assured payments based on plant availability (typically around 85 per cent), regardless of actual dispatch. This model is misaligned with the evolving role of thermal plants under flexibilisation, where utilisation is expected to decline. Additionally, existing PPAs embed return expectations for lenders and investors based on higher plant load factors, creating financial risks if dispatch reduces. On the fuel side, FSAs often require fixed coal offtake commitments, which may become redundant under lower utilisation scenarios. These structural mismatches between PPAs, FSAs, and the operational reality of flexible thermal generation can lead to contractual disputes and litigation. A coordinated reform of these frameworks is therefore necessary to align incentives, reduce financial risks, and ensure smooth implementation of flexibilisation without future legal bottlenecks.

Recommendations for State Regulators

I. States need to issue flexibility related tariff policy: State ERCs ought to undertake tariff regulations for flexible operations to bring state and private units under their jurisdictions under compliance obligation. Currently, only five state ERCs have issued these tariff regulations. The CEA's phasing plan includes 15 states, thus showcasing that 10 states are yet to implement policies for flexible operations. Non-issuance disincentivises uptake and unreasonably burdens the complying units by necessitating lower generation for their units during dispatch schedules.

II. Driving Flexibility through State Power Utilities: State Power Corporations and DISCOMs should prioritise flexibilisation of state-owned coal-based thermal power plants through revised operational protocols, retrofit investments, and incentive-linked scheduling mechanisms. Since these utilities directly own and operate a significant share of India's thermal fleet, faster adoption of flexible operations at the state level can substantially accelerate RE integration.

III. Enhance demand forecasting: Electricity demand forecasting methodologies ought to be updated with a shift towards 4x4 km mapping, industrial and residential consumption mapping, and upscaling local weather forecasting capabilities. The closer the demand forecasting prediction is, the lower will be the ramping fluctuation for generation unit, reducing the impact of flexible operations on unit's life and equipment. Accurate and robust demand estimates are critical for informed coal fuel and generation planning. Spain's recent unexpected clouding event, which sharply reduced solar generation and contributed to a blackout, underscores the critical need for more robust demand and generation forecasting systems that can anticipate and manage short-term variability in renewable output. Additionally, this reduces the scale of RE curtailment as RE generation can be more accurately predicted.

Recommendations for Power Generators

- I. Undertake retrofit and operational readiness assessment:** The foundation of flexibilisation lies in unit-level assessment of both technical retrofit requirements and operational readiness. Generating utilities should undertake structured engineering evaluations to identify control system upgrades, equipment reinforcement needs, and operational envelope adjustments required for sustained low-load and ramping performance. The assessments should cover the following:
- **Technical retrofits:** Upgradation of plant systems to achieve lower minimum technical load, deployment of advanced control and automation systems, and identification of equipment modifications required to support frequent cycling and ramping.
 - **Operational measures:** Strengthening maintenance practices, improving fuel quality management to ensure stable combustion at low loads, and enhancing operational protocols for flexible operation.
 - **System integration:** Preparing units for participation in ancillary service markets and real-time grid support mechanisms.

Early identification of these requirements enables realistic cost estimation, reduces execution uncertainty, and supports timely engagement with OEMs, suppliers, and regulators. The studies should catalogue plant-specific modification pathways, prioritise interventions, and align implementation sequencing with the national phasing framework.

II. Upskill workforce programme: Flexible operation places new operational demands on plant personnel, requiring continuous monitoring of ramp behaviour, transient equipment stress, and interaction with automated dispatch signals. Existing staffing structures and training regimes remain largely oriented toward baseload operation, creating capability gaps that can affect reliability and equipment health. Power generating companies should therefore establish structured training and transition programmes focused on ramp management, transient monitoring, and digital control interaction. Building operator capability will reduce operational risk, strengthen equipment protection, and improve confidence in sustained flexible operation.

III. Enable OEM provider engagement: Information asymmetries regarding equipment modification pathways, performance limits, and operational adjustments often slow adoption. The effectiveness of plant-level flexibility deployment is contingent on transparent information sharing regarding equipment health and overall performance, while consistent tracking and data recording will aid faster integration of new systems for flexible operations. Unit management ought to train plant personnel to ensure a coordinated effort with OEM providers for deployment efficiency.

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India's non-fossil based installed capacity has surpassed fossil-based capacity, fundamentally reshaping the power grid. Over the past decade, the share of solar energy has increased 3.5-fold to reach 140 GW, and with 100+ GW under construction, the daily power generation mix is now permanently altered. Coal-based thermal energy operations are shifting from consistent baseload to a more adaptable role, accommodating RE generation, especially during daytime. The unified national GRID requires flexibility from its largest energy resource.

To equip the fleet to operate flexibly, the Government of India notified the *Central Electricity Authority (Flexible Operation of Coal-based Thermal Power Generating Units) Regulations, 2022* on January 25, 2023. The phasing plan aims to transition India's coal fleet to a minimum technical load of 40 per cent while enhancing each unit's ramping ability above one per cent per minute.

This report examines India's progress in implementing coal flexibilisation while evaluating the technical, economic, regulatory, and institutional barriers shaping the transition. It assesses the costs of integrating flexible operations via retrofits and draws lessons from international experience in China, Chile, and Germany. Through system-level appraisal and policy analysis, the report highlights the decarbonisation potential embedded in accelerating its execution. Built with inputs from sector experts, the research aims to strengthen regulatory and tariff frameworks, empowering coal-based thermal power to support higher RE integration while maintaining grid reliability and affordability.



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