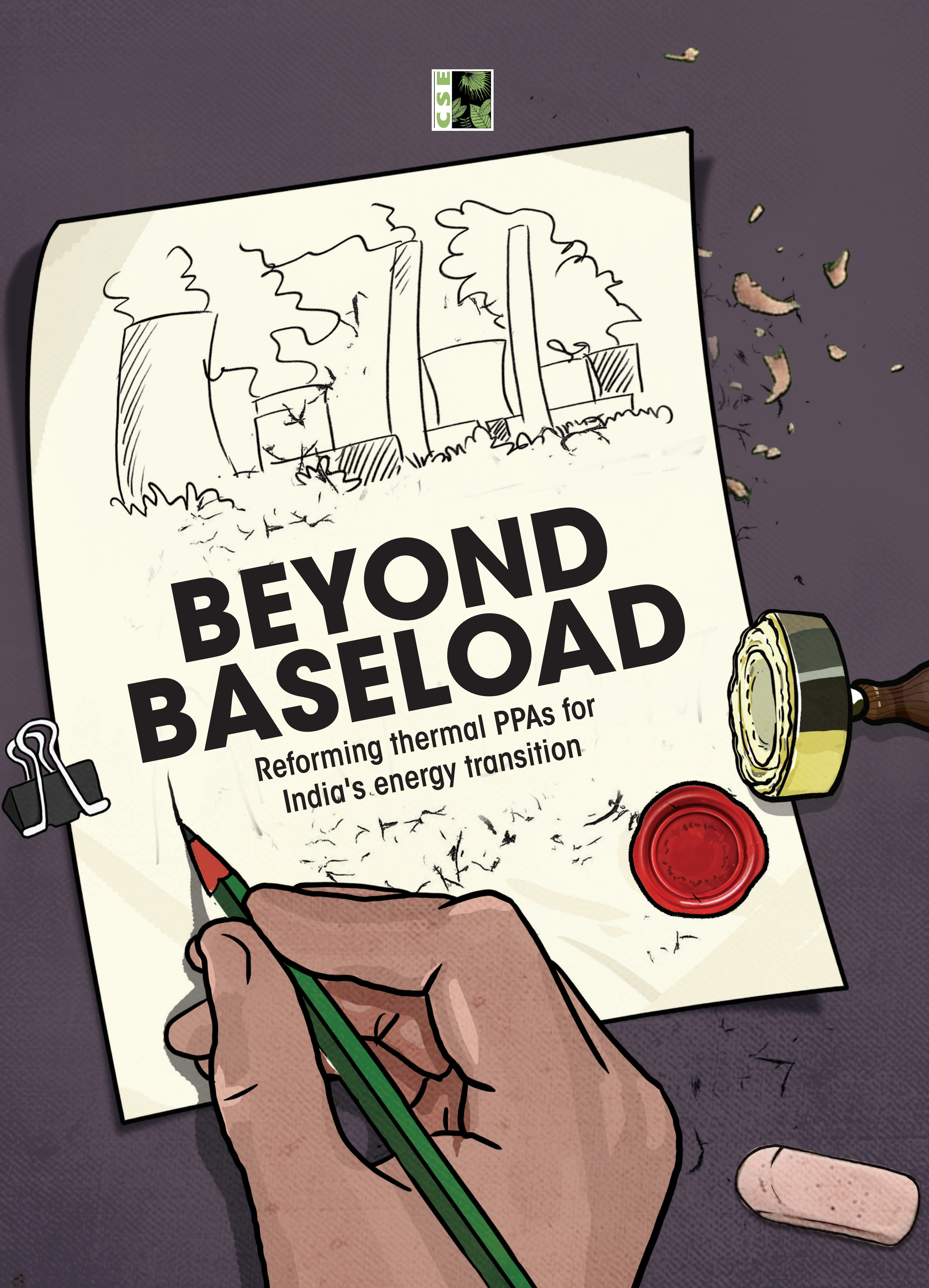
BEYOND BASELOAD

Reforming thermal PPAs for India's energy transition



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Reforming thermal PPAs for India's energy transition

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Executive Summary

The changing role of coal in India's power system

India's electricity sector is undergoing a fundamental structural transition. Over the past decade, installed solar capacity has increased from **2.82 gigaWatt (GW) in FY 2013-14 to 150.6 GW in FY 2025-26**, transforming the operational profile of the country's coal fleet. Solar generation has increased from contributing roughly **one unit for every 19 units of coal generation in FY 2019-20 to one unit for every seven units of coal generation in FY 2025-26**. While coal continues to provide the backbone of grid reliability, its role is steadily shifting from continuous baseload generation towards a flexible balancing resource that supports renewable energy integration. India's current coal fleet — as of July 2026 — is sized at **228.6 GW** and is still expanding with a tentative built up of above 300 GW targeted in the coming decade.

This transition has altered how coal plants operate, but not the commercial contracts that govern them. Most thermal Power Purchase Agreements (PPAs) continue to reflect an era of power shortages and high coal utilisation, with payments, operational obligations and risk allocation designed around sustained baseload operation. As renewable energy penetration increases, the disconnect between evolving grid requirements and legacy contractual structures is becoming increasingly important for consumers, procurers and generators alike.

Thermal PPAs: The why and the wherefore

Much of the policy discourse on coal transition has focused on technical flexibility, renewable energy deployment and market reforms. Comparatively little attention has been paid to the contractual framework that ultimately governs how thermal power plants are financed, operated and paid.

This report addresses that gap by examining thermal PPAs as a critical component of India's power transition. It evaluates how long-term contracts influence consumer costs, operational incentives and RE integration, and whether the existing framework remains suited to the changing role of coal. In doing so, it brings together legal analysis, financial modelling and operational assessment to examine PPAs not merely as commercial contracts, but as instruments that increasingly shape the economics of India's electricity transition.

What this report offers

The report begins by explaining the governance framework and commercial architecture of thermal PPAs before analysing the economics of greenfield coal contracts and the long-term cost implications of existing PPA structures. It then presents an RTI-based assessment of coal PPA lock-ins across select states and examines the contractual gaps relating to efficiency, emissions and flexible operation.

Building on these findings, the report evaluates the impact of renewable energy integration on coal utilisation, explores legal pathways for contractual reform through renegotiation and regulatory mechanisms, and proposes key clauses for a ***Modernised Thermal PPA Framework*** comprising new contractual definitions, suggestive clauses and policy recommendations to reform thermal PPAs while preserving contractual certainty. It draws from the case studies of Germany's coal phase-out act, Nabha Power's sale to Torrent Power, TATA Mundra UMPP's PPA renegotiation and Bihar ERC's greenfield coal PPA's discovery to provide practical insights.

The key findings at a glance

- **PPA categorisation blind spot:** Existing regulatory categorisation treats all PPAs exceeding five years as *"long-term"*, despite significant differences in financial exposure, contractual lock-in and system-planning implications between moderate-duration and 25-year contracts.

- **Long-term lock-in via PPAs:** RTI-based research mapped **67.1 GW** of contracted coal capacity across responding utilities in eight states, with almost all capacity tied to long-duration PPAs and the largest concentration of contractual expiry falling in the 2030s. BEST, Mumbai, is an exception, using shorter-duration PPAs.

- **Lower-utilisation cost trap:** Increasing renewable generation and daytime reduction of coal generation can leave substantial thermal capacity underutilised while fixed-cost obligations remain, increasing the effective cost of each unit of electricity generated.

- **The PPA tenure trade-off:** Extending a benchmark coal PPA from 11 to 25 years lowers the annual capacity tariff creating a saving of 70 to 114 paise/kWh, but tariff saving reduction more than doubles the cumulative consumer payout.

- **The fixed-cost payout multiplies over time:** A 25-year PPA for a 2,400-MW project could generate approximately ₹1.75 lakh crore in fixed revenues against an estimated capital cost of ₹27,600-31,200 crore, equivalent to roughly 5.6-6.4 times the initial investment under the stated availability assumptions.

- **Substantial daytime surplus coal capacity:** Rising solar generation has reduced the daytime operational requirement for coal, with CSE analysis estimating 45.72 GW of net surplus coal capacity at 55 per cent MTL, increasing to approximately 80 GW at 40 per cent MTL after accounting for auxiliary consumption and planned outages.

- **The toll-gate effect:** Even after project debt is typically retired within 10-12 years, long-term PPAs can continue to generate fixed-capacity payments and equity returns for the remaining contract period, creating a prolonged payment obligation beyond the primary capital-recovery period.

- **Fuel supply agreement lock-in**: FSAs can create a second layer of commercial lock-in by embedding long-term coal supply commitments alongside thermal PPAs. Germany's €4.35 billion negotiated compensation for RWE and LEAG reinforces the need to align FSA commitments with PPA reform and changing thermal utilisation.

- **PPA renegotiation as a plausible pathway:** The TATA Mundra UMPP demonstrates that even competitively bid Section 63 PPAs can be amended through mutual agreement demonstrating the potential for negotiated contractual adaptation to changing commercial circumstances.

Major recommendations

To enable PPAs as key tool for shifting coal-based thermal power from baseload to a flexible resource, the report proposes:

1. **Update the model PPA:** Revise the Model Thermal Power PPA to reflect the evolving role of coal, including provisions for operational efficiency, emission intensity, flexible operation, differentiated solar and non-solar hour requirements, and other model clauses suggested in the report.

2. **Make periodical PPA portfolio review mandatory:** Require DISCOMs and Power Corporations to periodically assess existing thermal PPA liabilities against evolving system requirements, including the options of renegotiation, tenure revision and negotiated exit.

3. **Establish a framework for PPA renegotiation and exit:** Develop standard principles for voluntary renegotiation, tariff adjustment and negotiated exit, with compensation limited to genuine unrecovered costs and appropriate treatment of existing financial obligations.

4. **Apply a strict system-need and least-cost test for PPAs:** Require new long-term PPAs to demonstrate system need and assess their total financial obligations against alternatives such as RE with storage, rather than relying on headline tariffs alone.

5. **Align flexible operation regulation with contractual / financial reforms:** Align technical requirements for flexible operation with appropriate changes in law, cost recovery and tariff adjustment mechanisms, while making flexible operation the foundational regulatory expectation and limiting exceptions.

6. **Differentiate availability factor for solar and non-solar hours:** Review the uniform annual availability factor to reflect different system requirements during solar and non-solar hours, aligning thermal capacity payments more closely with actual system needs.

7. **Incentivise efficient, low-carbon thermal generation:** Establish measurable efficiency and emission-intensity benchmarks and incentivise better-performing thermal units through Merit Order Dispatch preference or performance-linked mechanisms to reduce fuel consumption and CO_2 emissions.

8. **Align regulation and fuel-supply arrangements with PPA reform:** Align FSA commitments and coal offtake quantities with revised operational and PPA requirements, allowing fuel arrangements to be reduced, restructured or released where lower thermal utilisation reduces coal requirements.

Collectively, these recommendations reaffirm the central premise of the report that India's long-term thermal PPAs, while successful in enabling capacity creation and investment certainty, now require a contractual evolution to remain aligned with the changing realities of the power system.

1. Introduction

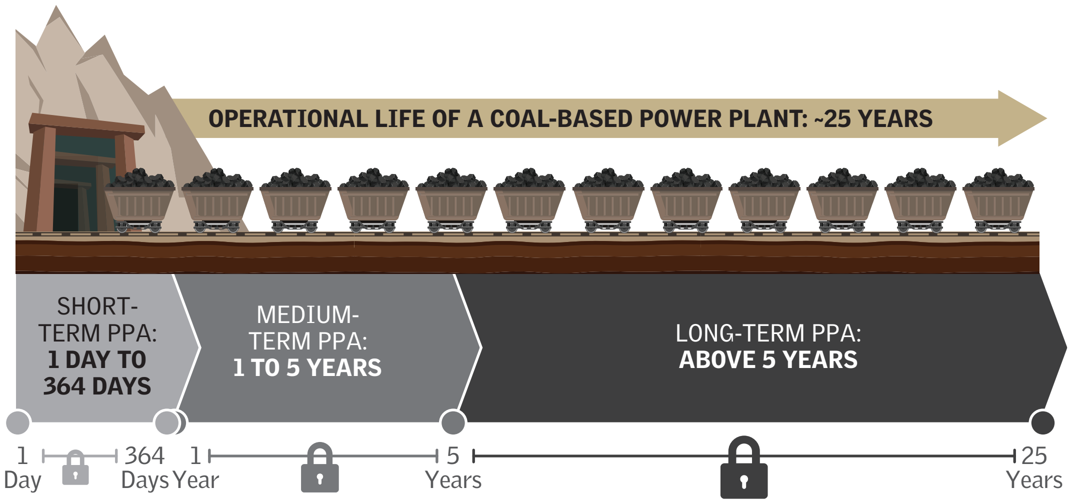
A Power Purchase Agreement (PPA) is the primary contract under which a power generator agrees to supply electricity to the procurer, typically a distribution licensee or a state power corporation in the Indian context. Visibility of contractual tenure along with certainty of revenue are essential components for all power developers. These components are critical for creditors to provide long term finance to plant developers. Power generation, especially coal-based thermal power has a long development period, with land acquisition, equipment purchases and necessary fuel storage infrastructure built up requiring a lengthier time period than a renewable energy (RE) generation project.

On the other hand, a distribution company (mostly DISCOMs in India) needs certainty over its energy demands for a consistent time frame. Power requisition is a part of the long-term planning architecture and is now governed under each DISCOM's Resource Adequacy Framework (RAF). PPA is the formalised instrument that creates this bridge. Power providers get certainty of income flows for their production and the distribution companies get assurance on power supply.

Historically, the PPA architecture in India has been built around the context of power supply shortages owing to inadequate generation capacity addition. Capital constraints further limited the pace of infrastructure development required to meet growing electricity demand. Consequently, the power sector came to be treated as a strategic heavy industry, with long-term contracting structures evolving around coal-based generation. Under the amended PPA definition framework issued by Ministry of Power, PPAs are broadly categorised as short-term PPAs ranging from one day to 364 days, medium-term PPAs spanning one to five years, and long-term PPAs extending beyond five years. However, this categorisation also creates a broad contractual spectrum wherein a coal plant with an operational life and financial recovery horizon of nearly 25 years continues to fall within the same "long-term" category as contracts marginally exceeding five years, despite the substantial difference in lock-in duration, cost recovery exposure, and system planning implications between the two.

The transition with RE integration has changed the dynamics. Today, the power system procures power that includes a mix of RE and fossil fuel-based energy generation, requiring coal-based TPPs to ramp down during solar hours to

Figure 1: The problem with PPA categorisation



Source: CSE analysis of Ministry of Power guidelines

accommodate RE into the generation mix — hence, changing the fundamental nature of the operation on a daily basis. Yet, the contractual rigidity provided by PPAs locks in the payment obligations despite asset underutilisation.

RE integration and lower utilisation

The RE addition underway in India's power system is fundamentally altering the utilisation profile of coal-based power plants. Traditionally designed and financed as baseload assets operating at consistently high load factors, coal units are increasingly being required to operate flexibly to accommodate rising shares of renewable energy, particularly solar generation during daytime hours.

To contextualise this, let's take an example: a new 660 MW coal unit operating at 85 per cent availability and near-continuous full-load conditions could potentially generate nearly 115 TWh of electricity over a 25-year period. However, as renewable penetration increases, coal units are progressively ramped down during solar-rich hours and are no longer dispatched uniformly across the day.

The solar power generated during daytime requires coal-based thermal units to reduce their generation outputs closer to their Minimum Technical Load (MTL) of 55 per cent for approximately eight hours of daytime. Accounting for outages, maintenance and auxiliary consumption of the unit itself, an estimated PLF of 68 per cent is assumed to calculate the scale of underutilisation at the unit level (*see Figure 2*).

Figure 2: RE integration and underutilisation of coal

Source: CSE analysis based on hypothetical utililisation scenarios

For power purchasers, this represents a structural transition in the economic and operational role of coal generation. Under a flexible dispatch regime where the plant operates at reduced daytime loads and achieves full-load operation only during part of the intended operating window, the same unit's lifetime electricity generation can decline to nearly 73.6 TWh, implying that roughly 41.85 TWh of generation potential remains underutilised over its operational life. This reflects a broader systemic reality where coal capacity increasingly serves as balancing and reliability support for renewable integration rather than functioning as a pure baseload resource. Consequently, power procurers need to reassess long-term utilisation assumptions, cost recovery structures, and procurement strategies within the PPAs as installed coal capacity remains essential, but its annual energy contribution progressively declines.

The system cost of coal

Understanding the cost structure of coal-based power generation is becoming increasingly important as the role of coal plants transitions from traditional baseload providers to flexible balancing resources in renewable-rich grids. Under the public-private partnership (PPP) model, states typically facilitate the development of large thermal power projects by providing land on concessional lease terms to private or public generators, who then finance, construct, and operate the asset over a 25-30 year period. The arrangement historically enabled states to secure long-term firm power supply without directly funding large infrastructure investments, while developers recovered costs through long-duration power purchase agreements. However, the economics underpinning these projects are deeply capital intensive. A modern 660-MW supercritical coal unit today requires an estimated investment of nearly Rs 7,590-8,580 crore, equivalent to roughly Rs 11.5-13 crore per MW of installed capacity, with financing generally structured through a 70:30 debt-equity model.

The long tenure of coal power contracts was originally justified by the absence of viable substitutes for firm and dispatchable power at scale, making coal the backbone of round-the-clock electricity security for states and distribution utilities. Long-duration agreements provided developers adequate time to recover large upfront investments through stable, high-utilisation operation, while ensuring assured power availability for the grid. Over a 25-year recovery horizon, a project financed through 70 per cent debt at 8 per cent interest and 30 per cent equity expecting 15 per cent returns can ultimately require cumulative recovery amount far above the original investment. This model functioned effectively when coal plants consistently operated at high plant load factors and generated large volumes of electricity across their lifetime.

However, with rapid scale-up of hydro balancing resources, energy storage systems (ESS), and renewable integration strategies, the historical dependence on coal as the only scalable source of firm power is gradually shifting. Coal units are increasingly required to ramp down during renewable-rich hours and operate more flexibly, reducing lifetime generation output even as fixed recovery obligations remain largely unchanged. Consequently, the same long-term contractual structures that once underpinned energy security are increasingly emerging as a system cost challenge, where capital recovery must now be spread across fewer units of electricity generated.

Rigidity of PPAs

As observed in CSE's 2025 publication *Decarbonizing the Coal-based Thermal Power Sector in India*, significant variation exists in the operational and environmental performance of coal units across the country — yet, utilisation decisions continue to be driven largely by cost structures embedded in long-term PPAs. This often leads to cleaner and more efficient units remaining underutilised, while older and less efficient plants continue operating under assured contractual arrangements.

Most PPAs also lack performance-linked standards related to efficiency, emissions, flexibility, or ramping capability, making operational performance largely irrelevant to dispatch priority and weakening incentives for technological and environmental improvement.

More broadly, rigid long-term PPAs have created non-competitive islands within the power system, insulating contracted generation from evolving grid realities and market-based performance signals. While the grid increasingly requires flexibility, balancing capability, and efficient dispatch, legacy PPAs continue prioritising fixed recovery and assured offtake. In this context, overlooking PPA structures remains a major omission in discussions on coal flexibilisation and power sector transition. Without performance-backed procurement frameworks, the system risks locking consumers into higher-cost and environmentally suboptimal generation, even as alternatives such as hydro, storage, and hybrid renewable systems become increasingly viable at scale.

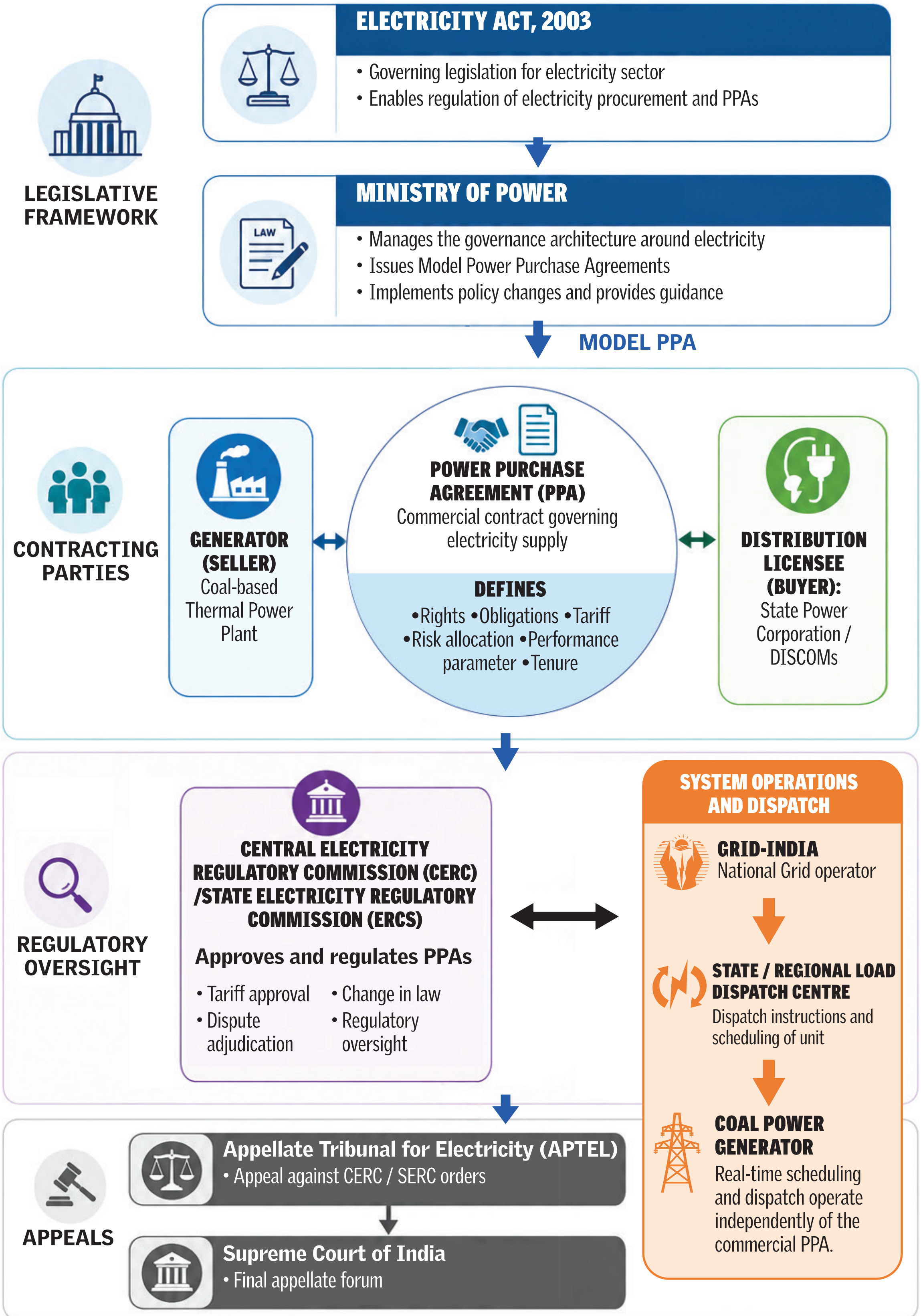
The report's flow and policy direction

This report seeks to examine how existing PPA structures for TPPs are increasingly misaligned with India's evolving power system realities, environmental goals, and cost optimisation requirements. Building on CSE's broader assessment of coal flexibilisation and thermal power utilisation, the study analyses how long-term PPAs raise costs for underutilised coal assets, lock-in inefficient generation, and weaken incentives for operational and environmental performance improvements.

The report begins by examining the governance framework and commercial architecture of thermal PPAs, before analysing the economics of greenfield coal PPAs and the long-term cost implications of existing contractual structures. It then presents an RTI-based assessment of coal PPA lock-ins across select states, followed by an examination of the contractual gaps that limit efficiency, emissions reduction and flexible operation. Building on these findings, the report evaluates legal pathways for reform, including renegotiation and contractual restructuring, and concludes by proposing a **Modernised Thermal PPA Framework** with suggestive clauses and policy recommendations to better align future PPAs with India's changing power system.

Collectively, the report aims to demonstrate that modernising thermal PPAs is not only essential for improving cost efficiency and facilitating RE integration, but also for ensuring that long-term contractual arrangements remain aligned with India's evolving electricity sector.

Figure 3: Governance of PPA



Source: CSE analysis of Indian regulatory documents

2. The Anatomy of a PPA

A thermal PPA, at its simplest, is a contractual agreement between the power generator and the power procurer which determines the operational architecture of the transaction. Beyond determining the price of electricity, a PPA establishes how revenues are earned, responsibilities are assigned, risks are allocated, and contractual obligations are enforced throughout the life of the project. For thermal power plants, where investments are recovered over two to three decades, the PPA provides the contractual certainty required to secure financing while assuring the procurer of reliable electricity supply.

The basic architecture

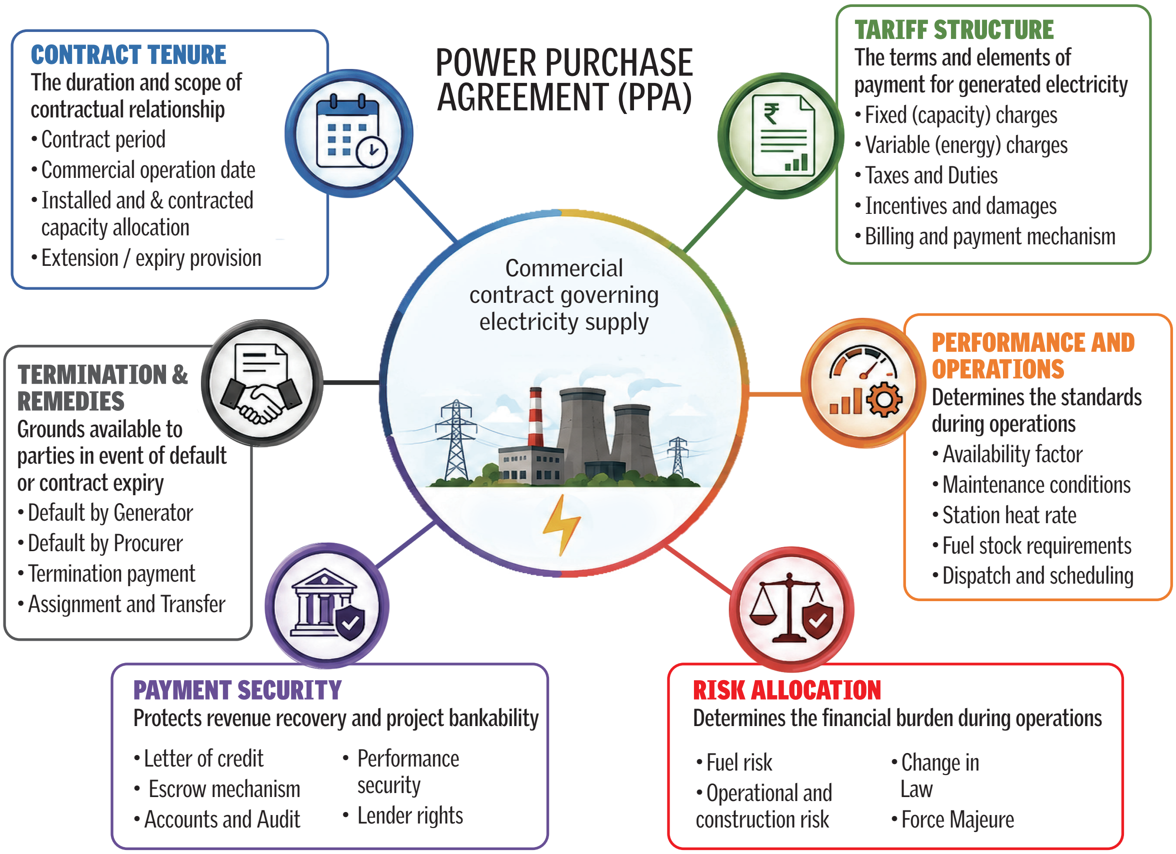
Although individual PPAs differ across procurement models and states, their underlying commercial architecture remains largely consistent. Modern PPAs typically define six broad dimensions of the contractual relationship: **contract tenure, tariff structure, operational performance, risk allocation, payment security, and termination and contractual remedies.** Together, these provisions determine the commercial viability of a project and influence the incentives faced by both generators and procurers over the duration of the agreement. The core components of the PPA constitute operational requisites like minimum station heat rate, the tariff framework encompassing cost calculation and terms of payment, and the duration of the contract among others.

Figure 4 provides a simplified overview of these principal components. Rather than presenting every contractual clause, it illustrates the key commercial pillars that collectively govern a thermal power project. Each of these components influences how risks and rewards are distributed between the contracting parties and, consequently, how investment decisions are made.

Long-term PPAs: Long-term PPAs typically remain in force for 20-30 years from the Commercial Operation Date (COD), providing the time horizon necessary for recovering capital investment and servicing debt. The contract defines the installed and contracted capacity, commencement and expiry of obligations, and, where applicable, provisions governing extension or continuation of supply.

Tariff structure: The tariff framework establishes how the generator recovers its investment and operating costs over the life of the project. By separating fixed and variable cost recovery, the contract creates predictable revenue

Figure 4: Anatomy of a thermal PPA — core components



Source: CSE analysis of PPAs accessed via RTIs

streams while ensuring that payments remain linked to defined operational and commercial parameters.

Performance obligations: PPAs specify the operational standards expected from both parties, including availability, maintenance requirements, scheduling and dispatch, and technical performance. These provisions align contractual payments with reliable operation of the generating station.

Risk allocation: A fundamental purpose of the PPA is to allocate commercial, operational and regulatory risks between the generator and the procurer. The agreement identifies which party bears the consequences of events, thereby reducing uncertainty over the life of the project. Usually, modern PPAs distribute the risk as indicated in *Table 1*.

Payment security: Long-term infrastructure projects require robust payment assurance mechanisms. PPAs therefore incorporate provisions such as

Table 1: Risk distribution under thermal PPAs

Risk	Typical allocation
Construction risk	Generator
Operational performance	Generator
Fuel procurement	Generator (subject to contractual provisions)
Fuel price variation	Depends on tariff structure
Dispatch risk	Procurer/System Operator
Market / offtake risk	Freedom determined by PPA with benefits usually shared equally
Payment risk	Procurer (mitigated through payment security mechanisms)
Regulatory change	Shared through Change in Law provisions
Extraordinary events	Governed through *Force Majeure* provisions

Letters of Credit, escrow arrangements and performance securities to enhance payment certainty, strengthen lender confidence and improve the overall bankability of the project.

Termination and contractual remedies: The agreement also establishes procedures for addressing contractual breaches, prolonged force majeure events and other circumstances that may lead to suspension or termination of the contract. These provisions specify the remedies available to each party while preserving contractual certainty throughout the project lifecycle.

The key takeaways

PPAs are founded on the principle of contractual certainty, providing a predictable framework for allocating rights, obligations, revenues and risks over the life of the project. These are designed to provide certainty rather than rigidity. Accordingly, PPAs do not generally contain explicit provisions prescribing when or how commercial terms may be amended.

At the same time, PPAs are fundamentally agreements between contracting parties. While renegotiation is not expressly provided for as a contractual process, neither is it generally prohibited. Where both parties mutually agree, commercial terms may evolve, subject to the applicable legal and regulatory framework.

Collectively, these provisions transform a PPA from a simple electricity supply contract into the commercial framework underpinning the financial viability of a thermal power project. Understanding these contractual building blocks is essential for assessing how existing PPAs influence the economics of coal-based power generation and the scope for future contractual reforms to facilitate renewable energy integration.

3. Greenfield Coal PPAs: An Economic Analysis

India is yet to announce a carbon peak: it has not declared its peak coal power capacity. In the meantime, the government aims to add 97 GW of new coal capacity to its power mix by FY 2034-35. The utility of redesigning the PPA structure can be understood from the cost analysis of a new coal PPA based on an existing format. The analysis will aid in showcasing the systemic lock-ins that the existing model creates.

This chapter examines the economic architecture around a greenfield coal PPA to assess whether the existing contractual structure balances project financing requirements with consumer interests. Beginning with the prevailing tariff framework, the analysis evaluates the lifecycle cost recovery of a representative coal project, examines the role of debt and equity financing in shaping fixed-capacity charges, and subsequently assesses how alternative PPA tenures influence annual tariffs and cumulative payment obligations.

The tariff framework: Cost-plus vs competitive bidding

India's Electricity Act, 2003 demonstrated the intent to move away from the negotiated route of power contracts to a market-driven method creating an inherent competition among generators to attain power contracts. In that light, the power projects also adopted the PPP model, in which the power procurer and generator divide the risks of the project in order to deliver on the timelines.

Under these terms, the project developer — the power generator — undertakes the initial cost of construction of the power plant until it is commissioned finally and the repayment is built into the tariff structure and repaid via per unit generated by the unit of the contract tenure. The power procurer provides the land and necessary clearances for the project in some cases. The level of support provided by the state varies from project to project. The tariff payout mechanism is governed within Sections 62 and 63 of the Electricity Act.

Under Section 62, the power procurer seeks out a power generator for power project and the cost is determined annually by the regulator. The project is developed on a cost-plus model in which direct and indirect costs along with a profit mark-up is paid out by the procurer, ensuring investment security. The promulgation of the **National Tariff Policy, 2006** (updated in 2016) added a preference for a competitive bidding process for power procurement governed by Section 63 of the Act.

Subsequently, the post-2010 power procurement has been through competitive bidding in which multiple generators bid by submitting the per unit electricity generation cost of their project — the bidder with the lowest stated tariff is preferred subject to coal supply linkages and the capacity to deliver on time.

While Sections 62 and 63 differ on the method of determining the power generator, the underlying policy of operations and cost assessment remain the same. As per the CERC tariff regulations, the thermal projects follow a 30:70 equity to debt ratio and the return on investment on these components is built into the PPAs. The rate of return on equity is between 14-15 per cent, while that on debt is between 7-8 per cent. The payout begins only from the date of generation, leading to elevated costs as the interest component gets added to the principal amount as costs are incurred from the onset itself.

Capital cost and the payment framework of new coal PPAs

In this segment, we note on how the current regulatory structure of PPAs embeds elevated cost for consumer use. We shall assess the absolute cost of a coal unit and the consumer payout based on length of the PPA.

Currently, according to industry estimates, the time needed to build a new coal power plant from the time of issuance of an LOA (Letter of Intent) is six years. The same estimate applies to coal plants under PPAs, as per a CSE RTI survey. The cost ranges between Rs 11.5 crore to Rs 13 crore per MW in general, subject to actual plant design layout and the technology involved, along with the coal supply structure. In *Table 2*, we note that the absolute cost of a 660/800-MW coal unit ranges between Rs 7,590 to 10,400 crore.

The cost estimates in *Table 2* are indicative as the actual payout rises based on the generation availability of the unit during its operational life. We analyse this by estimating the cost of the unit over its operational life in two distinct scenarios. First, the cost payout in a recently approved coal project: Bihar's 2,400-MW Pirpainti Thermal Power Station to be set up on a design, build, finance, own and operate (DBFOO) basis by Adani Power. This will showcase the inherent revenue return of a new coal unit over its 25-year PPA. Secondly, we calculate the cost and alter the tenure of the PPA and identify the scale of system savings via this.

Table 2: Cost of a new coal unit

Unit size with per MW cost	Equity component 30 % [in ₹ crore]	Debt component 70 % [in ₹ crore]	Total cost [in ₹ crore]
660 MW @ ₹11.5 crore/ MW	2,277	5,313	7,590
800 MW @ ₹11.5 crore/MW	2,760	6,440	9,200
660 MW @ ₹13 crore/MW	2,574	6,006	8,580
800 MW @ ₹13 crore/MW	3,120	7,280	10,400

Greenfield coal cost — BERC's discovered tariff

On August 27, 2025, the Bihar Electricity Regulatory Commission (BERC) approved the Bihar State Power Generation Company Ltd's (BSPGCL) allocation of long-term procurement of electricity from the Pirpainti Thermal Power Station. This 2,400-MW plant is to be set up at the discovered tariff rate of Rs 6.075/kWh with a fixed cost component of Rs 4.165/kWh. The fixed cost component includes the capital cost of building the plant, as this is where the tenure and rate of return is locked in via a PPA. Under the revised estimate, the final uptake from the approved units will be 2,274 MW.

In the calculation below, we have used the discovered tariff as the basis to calculate the maximum potential cash flow and the rate of return the PPA structure creates to identify the toll-gate effect PPAs may lead to. The actual earning varies as per the real cost of construction and the plant availability factor over 25 years.

The tariff payment is made on the basis of the availability factor of the generation unit, which is kept at 85 per cent of the unit's capacity. As long as the unit is available for the said time-period, it will be paid the fixed cost irrespective of the actual generation. Considering the annual maintenance requirements and unanticipated outages, our assessment assumes that the unit will be available for 80 per cent of its contracted time-period to arrive at revenue estimates.

Step 1: Capacity x PLF x Time = Generation [*100% nameplate possibility]
2400 MW x 1000kW/MW x (8,760 hours x 25 years) =
~ 525,600,000,000 kWh

Step 2: Generation x 80 % = billed generation [80% availability over 25 years]
~ 525,600,000,000 kWh x 0.80 = **~ 420,480,000,000 kWh**

Step 2: Generation x fixed cost tariff = absolute payout
~ 420,480,000,000 kWh x Rs. 4.165
= ~ Rs. 1,751,299,200,000/- / × **~1.75 lakh crore**

To calculate the embedded payout range, we need to compare the total payout with the capital cost and the equity infusion by the project developer.

Capital cost of the project (industry estimate): 2,400 MW x Rs 11.5/13 crore
= ~ **Rs 27,600 - 31,200 crore**

Equity infusion by project developer (assuming 30% cap): 30% of capital cost
= ~ **Rs 8,280 — 9,360 crore**

Even under a conservative performance assumption where the plant achieves an average of 80 per cent availability over its operational life to meet the availability factor threshold, the fixed capacity payout to the developer amounts to ₹1.75 lakh crore in this particular case. The total payout is 6.35 - 5.61 times more than the invested capital cost.

These are nameplate revenue numbers and the cost of debt may alter the actual profit a company may earn. These numbers state the maximum potential as per the existing PPA tenure structure. However, a better matrix is to estimate the average annual cash flow as debt financing, operational and auxiliary costs weigh on the unit's cash flow. The cost of debt determines if a unit turns a net positive in their operations.

Estimating the lifecycle cost returns

Simply comparing the total payout with the initial capital cost does not account for the fact that the investment is made upfront while the fixed-cost payments are received gradually over the next 25 years. To account for this timing, the analysis uses the Internal Rate of Return (IRR), which estimates the annualised return earned by the project over its lifetime.

For the sake of simplicity, the analysis assumes that the entire capital expenditure is incurred upfront (Year 0), although in practice it would be incurred progressively over the six-year construction period. Fixed-cost payments are assumed to commence after commissioning (from Year 7), and continue as equal annual payments over the subsequent 25 years. The calculation adopted computes IRR through this method:

$$C_0 = \sum_{t=7}^{31} \frac{A}{(1 + \mathrm{IRR})^t}$$

Where:

- C_0 = Initial capital cost (incurred at Year 0)
- A = Annual fixed-cost payout
- r = Internal Rate of Return (IRR)
- Payments begin in Year 7 (after six years of construction) and continue until Year 31

Table 3: Relationship between capital cost, annual fixed cost recovery and project IRR

~ Capital cost	Average annual fixed cost payout	IRR of cash flow [per annum]
~ Rs 27,600 crore	~Rs 7,005.1 crores	14.38 %
~ Rs 31,200 crore	~Rs 7,005.1crores	12.98 %

Discounting the annual fixed payout of Rs. 7,005.1 back across the entire 31-year timeline (six years of zero-payout construction followed by 25 years of generation) yields a full-lifecycle project IRR of 12.98 per cent to 14.38 per cent per annum. This aligns closely with the standard regulated Return on Equity (RoE) benchmark of 14-15 per cent historically used by regulators.

Leveraging the effect on developer's returns

This method actually understates the developer's true IRR. In real-world power plant construction, capital is spent gradually (e.g., 10 per cent in Year 1, 20 in Year 2, etc). Spending money later means the developer's capital is tied up for less time overall, which raises the effective return. By assuming 100 per cent of the CAPEX is spent on Day 1 (Year 1 frontloading), our model presents a conservative baseline.

While the estimated project IRR of 12.98-14.38 per cent appears broadly aligned with regulated returns, it reflects an unlevered return on the total project cost and, therefore, understates the developer's actual return on equity. Thermal power projects in India are typically financed on a 70:30 debt-to-equity ratio, implying that only Rs 8,280-9,360 crore of the Pirpainti project's estimated ₹27,600-31,200 crore capital cost is funded by the developer, with the remainder financed through long-term debt.

Toll-gate paradox of PPAs

Commercial debt for utility-scale thermal projects is generally available at interest rates of 7-8 per cent and is typically amortised over 10-12 years of commercial operation. During this initial period, a substantial share of the fixed-cost payout is allocated toward debt servicing. However, because the cost of debt remains lower than the project's overall return, financial leverage amplifies the developer's effective return on equity. Once the underlying debt is fully retired, the remaining fixed-capacity payments accrue almost entirely to the developer, driving equity returns materially higher than the project-level IRR.

This creates what may be characterised as a 'renteer' or 'toll-gate' effect. Although DISCOMs often facilitate land acquisition, water allocation and grid connectivity, they remain contractually obligated to continue paying capacity charges long after the underlying capital investment has been recovered. In effect, the utility continues paying a fixed charge for access to an asset whose construction costs have already been substantially recovered, raising important questions regarding the allocation of long-term risks and rewards under thermal PPAs. To avoid this, alteration of PPA tenure may be considered, and in the following section we estimate the possibility of this and its impact on consumer tariffs.

Cost implications of alternate PPA tenures

The previous section showed that cost recovery is amortised in a much shorter duration than the current 25-year PPA. The operational life of a coal unit is between 25-30 years, as per CERC's estimates. On the basis of the discovered fixed tariffs of seven recent coal projects, this report will present the annual fixed-cost recovery per MW and derive a capacity-weighted average fixed-cost recovery of ₹3.375 crore/MW/year. A capacity-weighted average is used to account for differences in project size, giving a representative fixed-cost recovery rate across projects rather than treating each project as equally significant.

Using this as the market benchmark, the analysis models an 800-MW greenfield coal unit and calculates the minimum capital recovery requirement under different PPA tenures. It then compares 6-, 11-, 15-, 20- and 25-year PPAs in terms of annual payments, total debt and equity payments, interest and equity returns, and cumulative consumer payout. Finally, it compares this minimum recovery requirements with the prevailing market fixed-cost tariff in ₹/kWh terms. This step-by-step assessment is important to the report because it shows that shorter PPAs are financially viable and can provide savings for DISCOMs.

Analysing the depreciation treatment

The CERC regulations of 2024, which govern the fees and charges of Load Dispatch Centres, factor in depreciation to a coal asset up to 90 per cent of its original value, with every unit retaining some resale value beyond their operational life. The current estimated rate stands at 3.34 per cent. Applying the same to a coal asset of any value, it will require 26.9 years to depreciate up to 90 years.

Under the cost-plus framework governed by Section 62 of the Electricity Act, depreciation constitutes a distinct component of the fixed-cost tariff approved by the regulator. It is designed to facilitate the gradual recovery of the capital invested in the generating asset over its useful life and is recovered through tariff in addition to the regulated return on equity, interest on debt and other admissible fixed costs. Consequently, depreciation does not reduce the developer's equity return; rather, it forms part of the total fixed-capacity payment made by the DISCOM. Usually, this is factored in by the commission while approving tariffs to pass on the benefits to consumers.

Under competitively bid PPAs governed by Section 63, individual tariff components are no longer identified separately. Instead, the discovered fixed charge represents a bundled payment that implicitly incorporates depreciation, among other capital-related costs. Although depreciation is no longer visible as a distinct tariff element, the economic outcome remains unchanged: the DISCOM continues to make the full fixed-capacity payment over the contract tenure, while the project developer internally allocates the proceeds.

Accordingly, for the purpose of this assessment, this CSE analysis treats the approved fixed-cost tariff as the total annual capital recovery available to the project. This approach ensures comparability across both Sections 62 and 63 PPAs and reflects the full long-term payment obligation borne by the procuring DISCOM, irrespective of the internal accounting or financial allocation undertaken by the project developer.

Estimating fixed cost mark-up

To compare the financial implications of alternative PPA tenures, it is also necessary to estimate the annual fixed-capacity payment embedded within the existing tariff structure. This helps in identifying the mark-up that exists within the discovered tariffs; the overall payout assessment to developer remains constant while determining the system costs borne by DISCOMs. We shall be using the assessment to identify the tariffs of seven recent coal projects and arrive at an average fixed cost tariff to be used for our assessment.

Step 1: Estimating the Maximum Annual Billing Capacity

The fixed-cost component of a thermal PPA is payable on the declared availability of the generating unit rather than the actual electricity supplied. Accordingly, the first step is to estimate the maximum annual billing capacity of one MW of installed capacity, assuming continuous availability throughout the year.

Annual Maximum Operating Hours: 365 ×24 = **8,760 hours**
Thus, **1 MW** of installed capacity operating at full availability represents:
1 MW × 8,760 hours = **8.76 million kWh** (**8.76 MU**)

This represents the maximum annual energy on which the fixed-capacity payment can be recovered under a PPA.

Step 2: Estimating the Annual Fixed-Cost Recovery per MW

The discovered fixed tariff, expressed in ₹/kWh, is converted into an annual capacity payment by multiplying it with the maximum annual billing capacity of one megawatt. This provides the annual fixed-cost recovery available to the project developer per MW of installed capacity under full availability.

Annual Fixed-Cost Recovery (₹ crore/MW/year)

$$\frac{\text{Fixed tariff (₹/kWh) x 8,760 hours x 1000 kW}}{\text{Rs 10,000,000}}$$

The annual fixed-cost recovery estimated above forms the basis for assessing the embedded capital recovery and financial returns under long-term thermal PPAs. We now utilise this mechanism to estimate the cost of seven coal projects.

As fixed-cost tariffs vary across individual projects owing to differences in bid year, financing conditions and project characteristics, the analysis adopts a capacity-weighted average annual fixed-cost recovery from recent thermal PPAs. This provides a representative estimate of the embedded annual capacity payment for assessing alternative PPA tenures.

Table 4: Long-term coal projects — discovered fixed-cost (2019-2025)

State and year of project	Capacity of the project (in MW)	Discovered fixed-cost (in Rs/kWh)	Annual unit mark-up rate (in ₹ crore/MW/ year)
Madhya Pradesh (Dec 2019)	1320	2.898	2.539
Maharashtra (Sep 2024)	1600	3.67	3.215
Uttar Pradesh (Oct 2024)	1500	3.727	3.265
West Bengal (Jan 2025)	1600	3.6	3.154
Assam (Feb 2025)	500	4.05	3.548
Madhya Pradesh (July 2025)	3200	4.22- 4.30	3.697 — 3.767 (midpoint: 3.732)
Bihar (July 2025)	2400	4.165	3.649

Source: Bihar Electricity Regulatory Commission, Case No. 36/2025

Weighted Average Fixed Tariff: **Rs 3.853/kWh**
Weighted Average Annual Unit Mark-up Rate: **Rs 3.375 crore/MW/year**

With an available mark-up rate, we need to first determine a baseline of CAPEX expense of a greenfield PPA, before using these valuations for our PPA tenure assessment.

New coal unit: Estimated CAPEX

Prior to assessing the financial implications of alternative PPA tenures, it is necessary to establish the baseline capital recovery requirement of a representative greenfield coal power project. This provides the minimum annual revenue that must be recovered by the developer before accounting for the additional commercial returns embedded within the fixed-cost tariff.

For consistency, the assessment adopts the 800 MW ultra-supercritical coal unit at Rs 13 crore/MW presented in *Table 2*, resulting in a total project cost of Rs 10,400 crore. The project is assumed to be financed through a conventional 70:30 debt-equity structure, comprising Rs 7,280 crore of commercial debt and Rs 3,120 crore of equity. As done previously within the chapter, we front-load the entire cost and the recovery begins at the end of year six, resulting in elevation of the costs before actual recovery. The analysis assumes a commercial borrowing rate of 8 per cent on debt and an annual return on equity of 15 per cent.

Debt at Commercial Operation Date (COD):
$\text{Debt}_{COD} = ₹7{,}280 \times (1.08)^6 = ₹11{,}552.45$ crore

Equity at COD:
$\text{Equity}_{COD} = ₹3{,}120 \times (1.15)^6 = ₹7{,}216.76$ crore

Total Minimum Recoverable Capital at COD:
$\text{Minimum Recoverable Capital}_{COD} = ₹11{,}552.45 + ₹\ 7{,}216.76 = \mathbf{₹18{,}769.21}$ **crore**

The two financing components are recovered differently. Debt represents borrowed capital that must be repaid over the financing period together with interest, resulting in an annual debt servicing obligation. Equity, on the other hand, is not repaid during the project life; instead, investors receive an annual return on the capital invested.

Impact of PPA tenure on CAPEX recovery

Having established the minimum recoverable capital at the COD, the annual fixed-capacity payment requirement is estimated across alternative PPA tenures. The assessment separately amortises the debt and equity components using their respective financing costs, thereby capturing the effect of longer recovery periods on both annual capacity payments and the cumulative financing burden borne by the procuring DISCOM. The detailed methodology on calculations is provided in *Annexure I*. While extending the PPA leads to reduction in annual payment obligations, it simultaneously increases the total interest and equity returns paid over the life of the contract.

The results highlight the inherent financial trade-off associated with extending PPA tenures. While increasing the recovery period from six to 25 years reduces the annual fixed-capacity payment by nearly 50 per cent, it more than doubles the cumulative consumer payout owing to higher debt interest and prolonged equity returns. Likewise, the equity returns jumped from ₹4,224.85 crore to ₹20,693.95 crore, reflecting the longer duration over which investors continue to receive returns on capital. Longer-duration PPAs lower annual capacity charges and improve short-term tariff affordability: they do so by extending the period over which consumers finance debt servicing and equity returns, thereby significantly increasing the overall long-term payment obligation borne by the procuring DISCOM.

Table 5: Pay-out analysis based on PPA tenure

PPA tenure	Annual debt payment (₹ crore/ year)	Total debt paid (₹ crore)	Interest paid (₹ crore)	Annual equity payment (₹ crore/ year)	Total equity paid (₹ crore)	Equity return earned (₹ crore)	Total annual capacity payment (₹ crore/ year)	Total Consumer Payout (₹ Cr)
	A	B = A x debt repayment period	C = B - initial debt	D = Capacity charge attributable to equity	E = D x PPA tenure	F = E - Initial equity	G = A + D	H = B + E
6 Years	2,498.97	14,993.84	3,441.39	1,906.93	11,441.61	4,224.85	*4,405.91*	26,435.44
11 Years	1,618.22	17,800.47	6,248.02	1,378.90	15,167.89	7,951.13	*2,997.12*	32,968.36
15 Years	1,349.67	20,245.01	8,692.56	1,234.19	18,512.84	11,296.08	2,583.86	38,757.85
20 Years	1,176.64	23,532.85	11,980.40	1,152.96	23,059.20	15,842.44	*2,329.60*	46,592.05
25 Years	1,082.22	27,055.49	15,503.04	1,116.43	27,910.71	20,693.95	*2,198.65*	54,966.20

Long-term costs of market tariff

While the previous analysis estimates the minimum annual capacity payment required to recover project costs under different PPA tenures, actual capacity charges are determined through competitive bidding and may differ from the financing requirement. To assess the long-term consumer payment implications of prevailing market tariffs, the capacity-weighted average fixed-cost recovery of ₹3.375 crore/MW/year derived from recent greenfield coal PPAs is applied uniformly across alternative contract durations. The weighted average fixed-cost recovery is calculated by applying the weighted average fixed cost tariff for an 800 MW unit.

This comparison illustrates how PPA tenure alone influences cumulative consumer payments, independent of the annual tariff discovered through bidding. The comparison highlights the fact that the capacity-weighted average fixed-cost tariff, derived from prevailing 25-year PPAs, is insufficient to recover the minimum financing requirement within six years. However, beyond that, the conclusion is uniform that while longer PPAs make tariffs seem commercially feasible, they lock consumers into substantially higher cumulative payment obligations over the contract life, besides burdening DISCOMs.

Furthermore, the analysis becomes more profound with the assessment of annual payout in tariff terms, i.e. Rs/kWh. *Table 7* shows that the overall tariff saving is minimal in market terms, even as the payout burden doubles.

The minimum capacity tariff represents the annual fixed-cost payment required to recover the capital cost of the representative 800 MW coal project. It therefore changes with the tenure: a longer recovery period lowers the annual payment. In contrast, the weighted average capacity tariff is based on the ₹3.853/kWh

Table 6: Comparison of Minimum Capital Recovery and Marked-up Fixed Cost Payment

PPA tenure	Minimum Annual Capacity Payment (₹ crore/year)	Minimum Consumer Payout (₹ crore)	Weighted Average Fixed-Cost Recovery (₹ crore/year)	Total Consumer Payout at Weighted Tariff (₹ crore)
6 years	4,405.91	26,435.44	2,700	16,200
11 years	2,997.12	32,968.36	2,700	29,700
15 years	2,583.86	38,757.85	2,700	40,500
20 years	2,329.60	46,592.05	2,700	54,000
25 years	2,198.65	54,966.20	2,700	67,500

weighted average fixed tariff derived from seven recent coal PPAs and represents the prevailing market-based fixed-cost recovery. This allows the analysis to show whether the reduction in the annual tariff as a result of extending the PPA is actually reflected in prevailing market tariffs, and how much the annual tariff changes even as the cumulative payment obligation increases. The 18-114 paisa saving on fixed costs translates into doubling of overall burden. These systemic cost savings can translate into larger savings for the DISCOMs.

The preceding assessment demonstrates that the financial consequences of long-duration PPAs are not merely theoretical, but have material implications for the long-term liabilities accumulated by procuring DISCOMs. The results show that extending the PPA tenure reduces the annual capacity payment, but increases the total payment obligation substantially. When applying the prevailing market fixed-cost recovery estimates of ₹2,700 crore per year, the total consumer payout rises from ₹16,200 crore over six years to ₹67,500 crore over 25 years. In tariff terms, this means that extending the PPA from six to 25 years reduces the minimum capacity tariff from ₹6.29/kWh to ₹3.14/kWh, while the market-based capacity tariff may continue to remain around ₹3.85/kWh.

The takeaway is, therefore, that the lower annual tariff under a longer PPA does not necessarily represent a lower overall cost; it simply shifts the burden into a longer payment commitment and results in a substantially higher cumulative payout by consumers and DISCOMs.

Building on this conceptual assessment, the following chapter evaluates the extent of this lock-in effect using RTI-based procurement data from select DISCOMs, quantifying the long-term capacity payment obligations embedded in existing thermal PPAs.

Table 7: Capacity tariff comparison under different PPA tenures

PPA tenure	Minimum Annual Capacity Payment (₹ crore/year)	Minimum Capacity Tariff (₹/kWh)	Weighted Average Fixed-Cost Recovery (₹ crore/year)	Weighted Average Capacity Tariff (₹/kWh)
6 Years	4,405.91	6.29	2,700	3.85
11 Years	2,997.12	4.28	2,700	3.85
15 Years	2,583.86	3.69	2,700	3.85
20 Years	2,329.60	3.32	2,700	3.85
25 Years	2,198.65	3.14	2,700	3.85

4. The States' PPA Lock-in

Power being a federal subject with a distributed architecture, states in India have a varied system of entering into PPAs. The last point of contact for the consumer is the electricity distribution company — the DISCOMs. Yet, the power of electricity procurement does not solely rest with them. Prior to the Electricity Act, 2003, power procurement was and continues to remain the function of the energy departments of the states or their respective power corporations. These bodies in turn allocate contracted power to various state-owned DISCOMs in their jurisdiction based on the power demand or lately, resource adequacy frameworks.

The impact of existing PPAs on financial health can be gauged from the scale of lock-in for each state's DISCOMs or their respective power corporations. The analysis of scale serves a two-fold purpose. Firstly, it showcases the book value obligation which determines their future payout needs. Secondly, knowledge of capacity lock-in aids in planning a window for future renegotiations and highlighting the financial risks of remaining tied to outdated contract structures.

RTI-based assessment of state PPA lock-in

This chapter talks about the PPA lock-in of select DISCOMs and highlights notable insights from their data. The findings presented are based on information obtained under the Right to Information (RTI) Act, 2005. Accordingly, the analysis covers only those publicly owned DISCOMs that have disclosed the details of their designated Public Information Officers (PIOs), including their correspondence addresses, thereby enabling the filing and processing of RTI applications.

RTI applications dated between January-March 2026 were submitted to DISCOMs/ Power Corporations of Assam, Bihar, Chhattisgarh, Haryana, Jharkhand, Karnataka, Kerala, Madhya Pradesh, Maharashtra, Rajasthan, Tamil Nadu and Uttar Pradesh. The applications sought the list of coal-based thermal power plants contracted by respective DISCOM, along with the contracted capacity via PPAs. The applications also sought the duration of each PPA along with the applicable time period under them. As of July 2026, no first appeals are pending, and the findings have been reported based on responses received till then.

No response was received from Assam, Chhattisgarh and Jharkhand. RTI applications to Bihar's two DISCOMs' — South Bihar Power Distribution Company

Ltd (SBPDCL) and North Bihar Power Distribution Company Ltd (NBPDCL) — were rejected at the first appeal stage.

In response to RTI applications to state DISCOMs of Madhya Pradesh (three DISCOMs — Madhya Kshetra, Poorv Kshetra and Paschim Kshetra Vidyut Vitran Company Ltd) and Uttar Pradesh (four DISCOMs — Purvanchal, Paschimanchal, Madhyanchal and Dhakshinachal Vidyut Vitran Nigam Ltd), information was partially provided: the data provided fell short of the total power procured/ allocated to these DISCOMs.

Detailed responses were received from the other six states. Kerala's State Electricity Board provides a high level of transparency, with a majority of the information available in the public domain via its website. MAHAVITRAN illustrates the information on the website, though copies of the PPAs are not provided. The other four states furnished the details after payment of cost towards paper printing as per the RTI Act. The disclosure is has been shown in *Map 1*.

State-wise PPA lock-in profiles of select DISCOMs

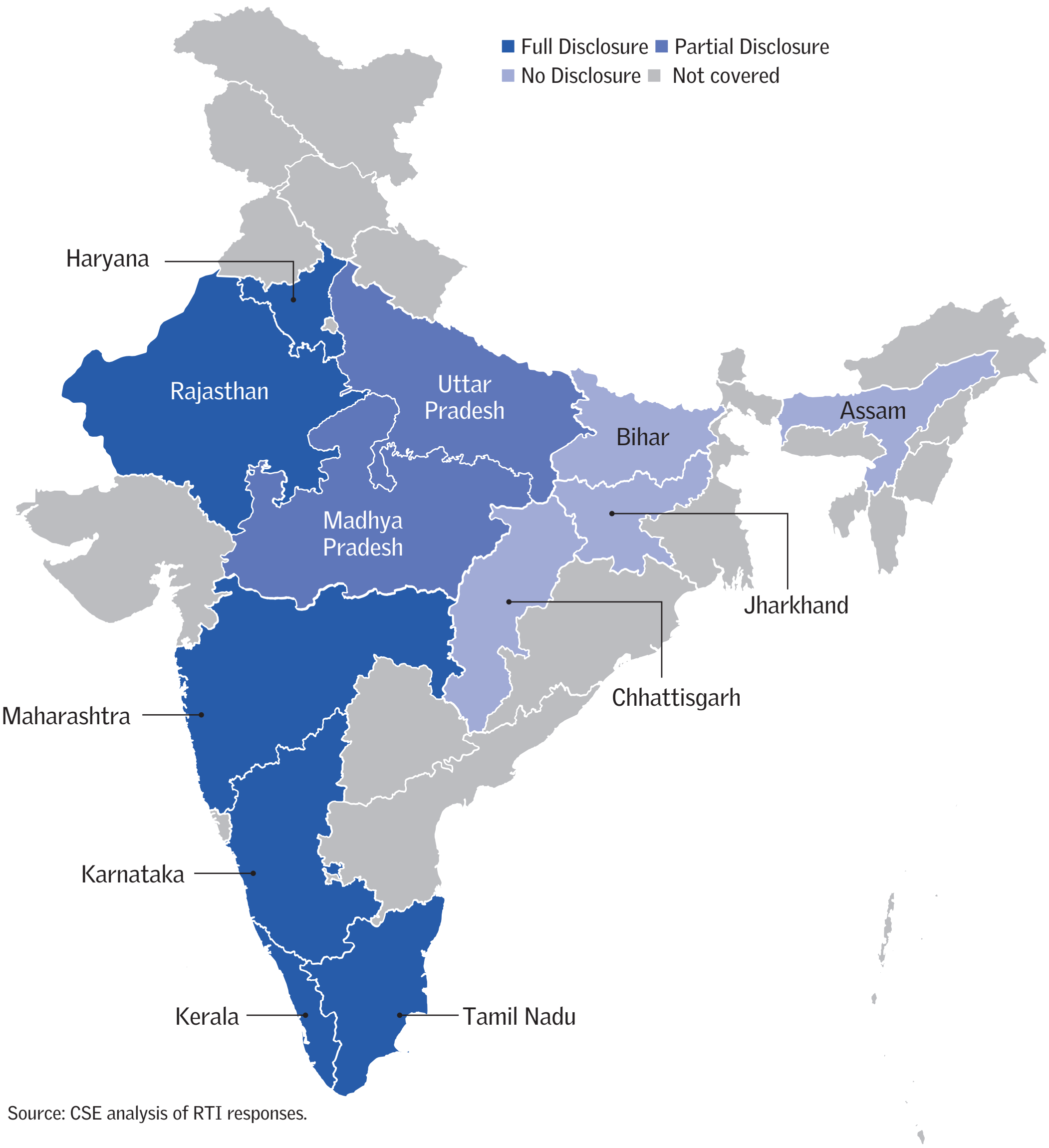
The RTI responses received from select DISCOMs and power corporations are mapped out in detail to highlight the existing thermal power procurement portfolio and the duration of contractual lock-in. The treemaps (*Graphs 1-9*) illustrate the distribution of contracted thermal capacity by PPA expiry year for each responding entity. Each block represents the quantum of capacity scheduled to expire in a particular year, enabling a visual assessment of the concentration of contract expiries over time. Larger blocks indicate higher contracted capacity scheduled to expire in a given year, while the colour gradient distinguishes individual PPA expiry years.

Evaluating India's PPA lock-in

The data from DISCOMs show that despite the altered definition of long-term power procurement being five-year and above, coal-based PPAs are locked-in for 25 years or more. The national treemap illustrates 2035 accounting for nearly 15.7 GW of contracted capacity, demonstrating the historical shift in coal expansion in the 2010s. Substantial PPA expiries emerge in 2028 (7.2 GW), 2032 (6.7 GW), 2031 (6.2 GW) and 2034 (6.0 GW), indicating that opportunities for large-scale contract restructuring are likely to emerge only gradually over the coming decade.

Yet, the norm of 25 years or above continues with Kerala, Tamil Nadu and Maharashtra data, reflecting PPA lock-ins beyond 2040s and into the 2050s. This represents the larger risk, as with RE's expansion, the power system dynamics are

Map 1: RTI response status of state DISCOMs and power corporations

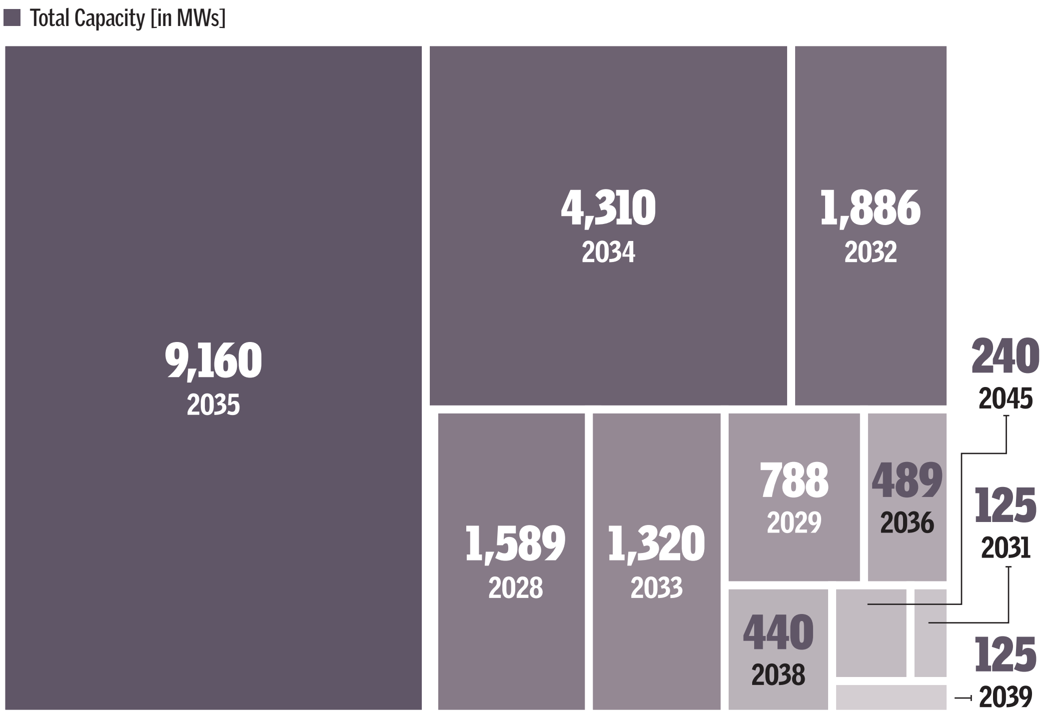


Source: CSE analysis of RTI responses.

not the same as in the 2010s. At the same time, India is aiming to expand its coal-based thermal power capacity beyond 300 GW. The new capacity addition based on existing PPA architecture presents a substantial financial risk beyond the obvious environmental one.

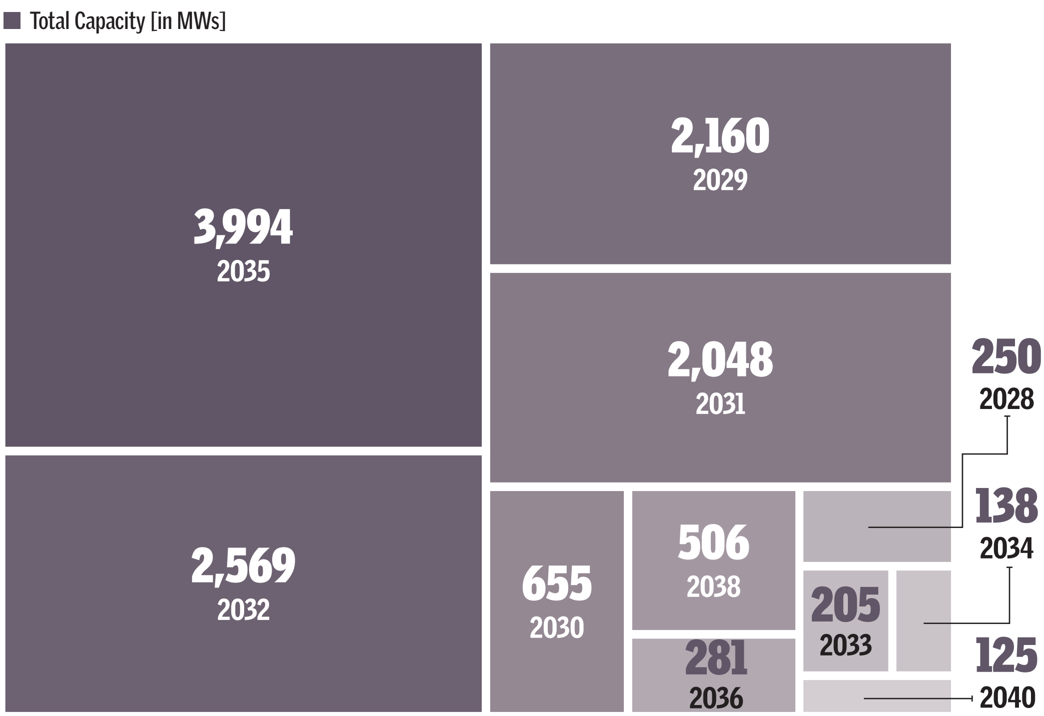
The national data also shows that a majority of the coal fleet is around 10-15 years old. Considering the fact that the PPAs are expiring in the 2030s, this fleet is possibly approaching the time when its respective debt components would be amortised. Therefore, it is important to provide a window of opportunity to DISCOMs/power

Graph 1: Maharashtra PPA Lock-in | 20,472 MW



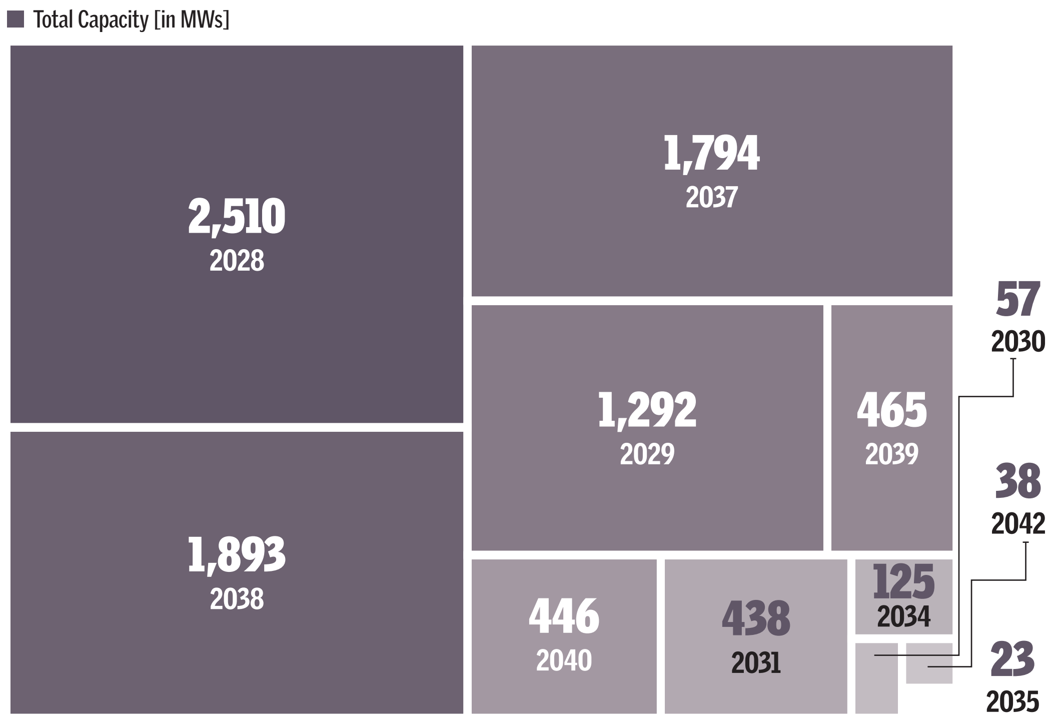
Source: RTI response of Maharashtra State Electricity Distribution Company Ltd. (MAHAVITRAN); Brihan Mumbai Electric Supply & Transport Undertaking (BEST)

Graph 2: Rajasthan PPA lock-in | 12,931 MW



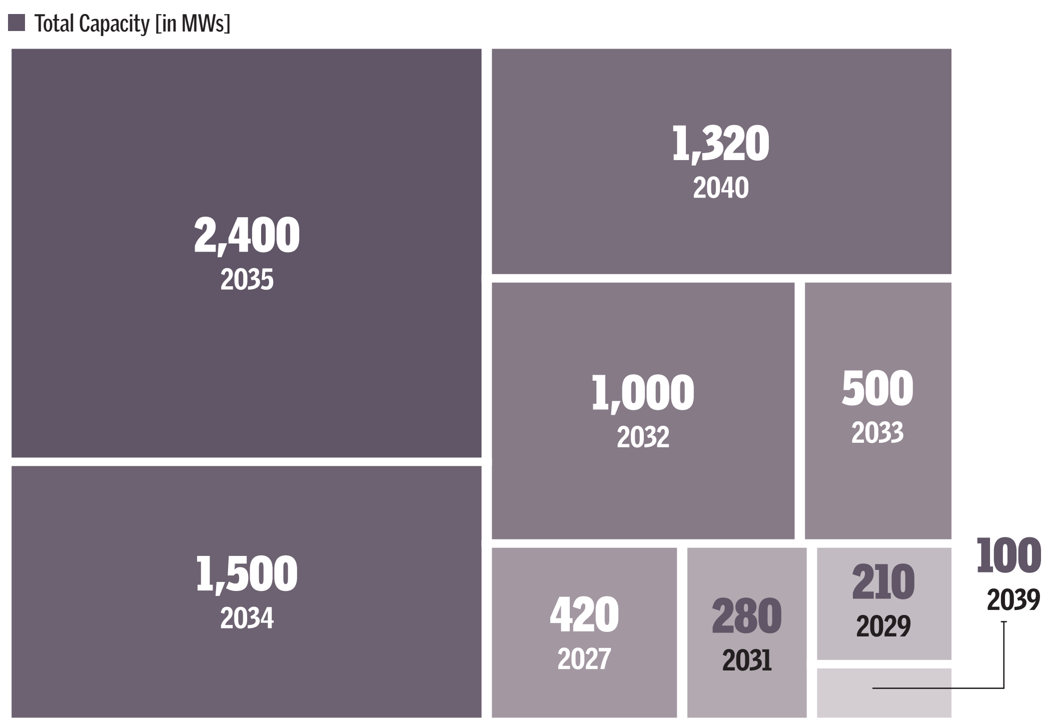
Source: RTI response of Rajasthan Urja Vikas and IT Services Ltd

Graph 3: Haryana PPA lock-in | 9,080 MW



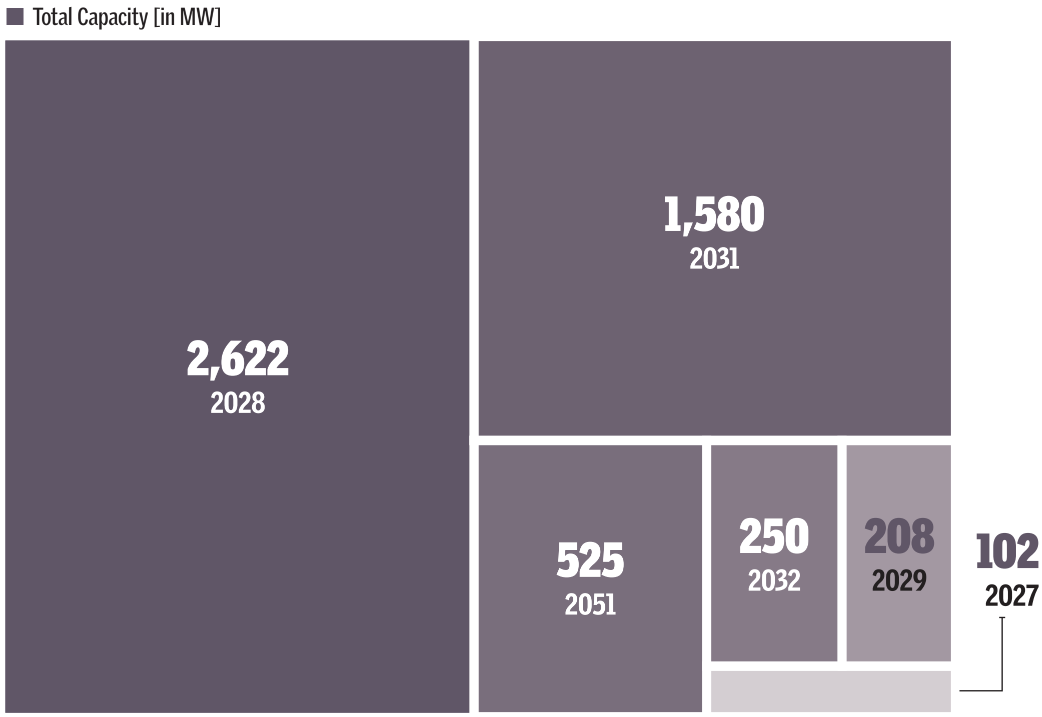
Source: RTI response of Haryana Power Purchase Centre

Graph 4: Kerala PPA lock-in | 7,730 MW



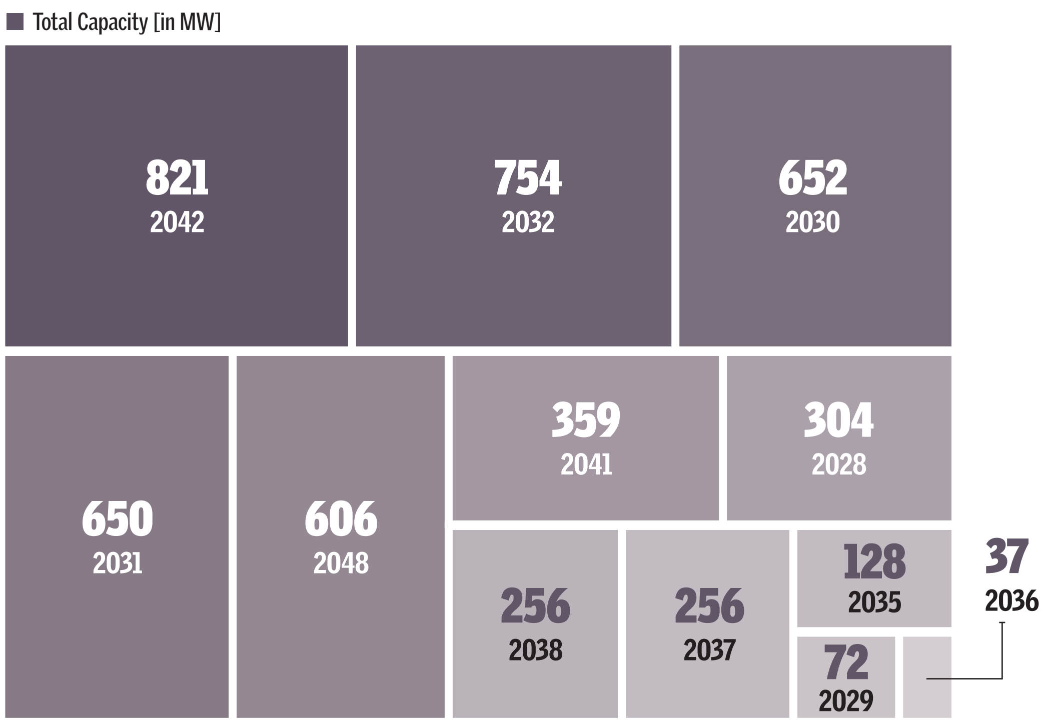
Source: RTI response of Kerala State Electricity Board (KSEB)

Graph 5: Tamil Nadu PPA lock-in | 5,287 MW



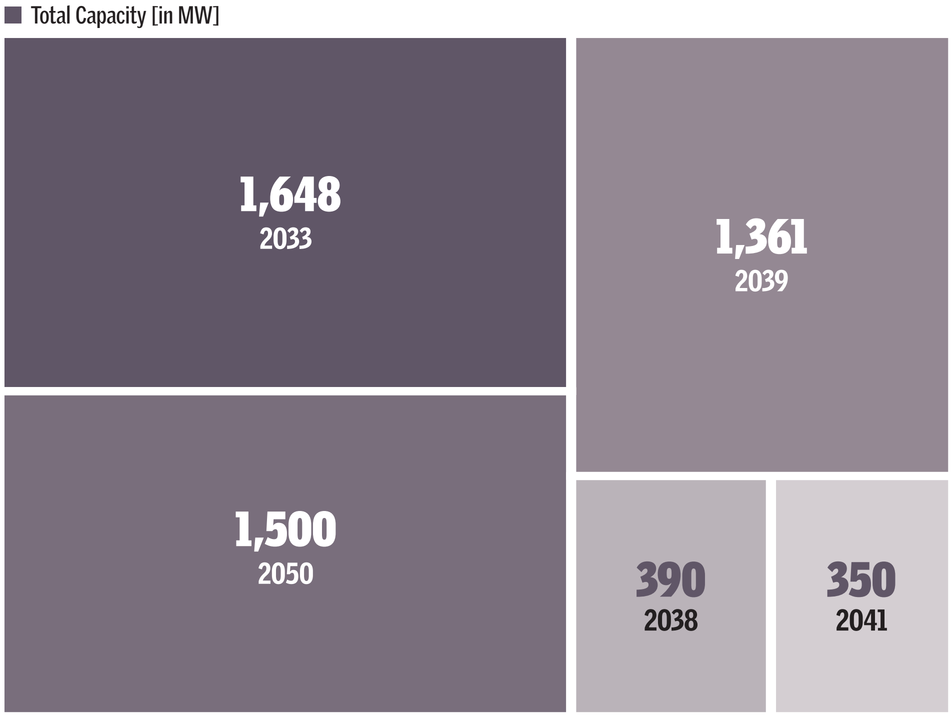
Source: RTI response of Tamil Nadu Power Distribution Corporation Ltd (TNPDCL)

Graph 6: Karnataka PPA lock-in | 4,894 MW



Source: RTI response of Bangalore Electricity Supply Company Ltd (BESCOM)

Graph 7: Uttar Pradesh PPA lock-in | 5,249 MW

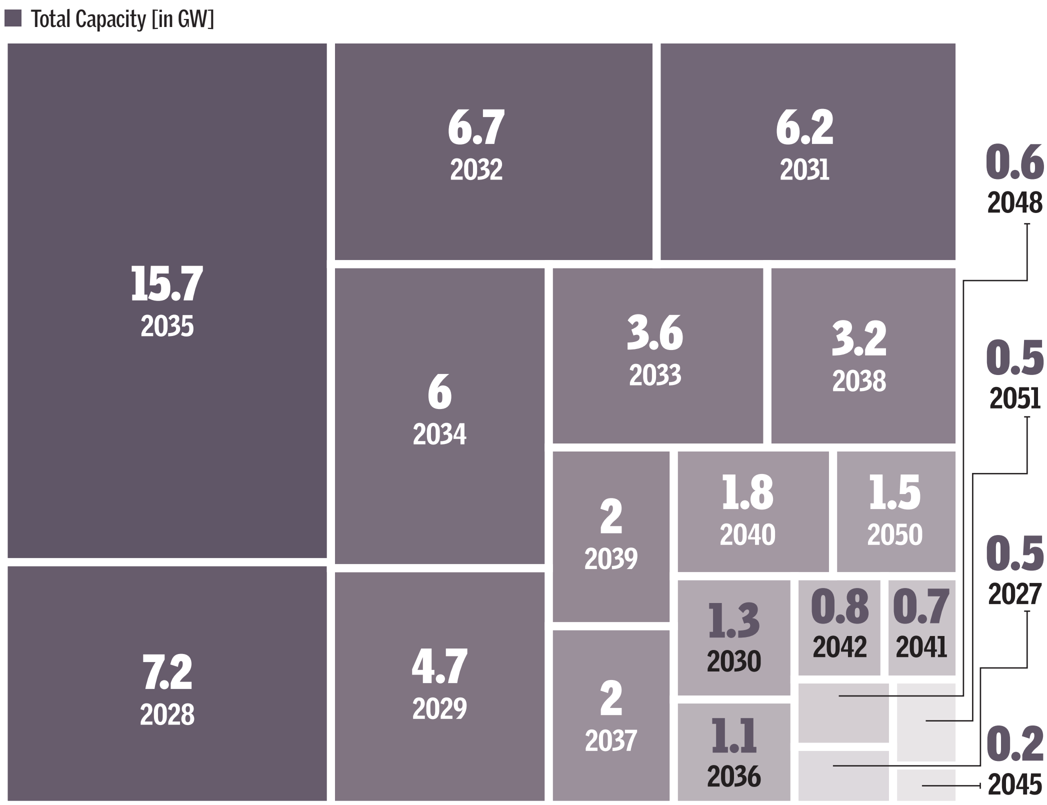


Source: RTI response of UP Power Corporation Ltd

Graph 8: Madhya Pradesh PPA lock-in | 1,477 MW

Source: RTI response of Madhya Pradesh Power Generating Company Ltd (MPPGCL)

Graph 9: India — select DISCOM's PPA lock-in | 67.1 GW



Source: CSE analysis of RTI responses from public sector DISCOMs

corporations to seek a review of the PPA terms through renegotiations to reflect the existing power system dynamics.

Notably, the BEST in Maharashtra is the only DISCOM with short-term coal-based thermal power PPAs (five-year periods). The contracted units of BEST have completed their operational life of 25 years, but the generators have continued operating due to good management. Their example points to a dual advantage: DISCOMs have the freedom to analyse their power demand at regular intervals, while the generator creates value in operations beyond the unit's life. This creates an additional benefit of lower power tariffs as the fixed cost recovery is built into the PPA. Simultaneously, it prevents the need for new coal units, thus avoiding the cycle of high costs and carbon emissions. BEST's model illustrates the fact that power generators can continue commercial operations without opting for 25-year PPAs.

COMMERCIAL VALUE OF LONG-TERM PPA: THE NABHA POWER ACQUISITION

In 2026, Torrent Power acquired from Larson & Toubro (L&T) its only operational power plant subsidiary, Nabha Power Ltd, for an enterprise value deal of Rs 6,889 crore. The move was approved by the Competition Commission of India (CCI) in April 2026, expanding the generation capacity of Torrent Power to 6.4 GW.

Torrent Power's acquisition of Nabha Power is a key metric to understand the value a long-term PPA provides to a coal asset despite rising RE penetration. Under the deal, Torrent is paying Rs 3,661 crore for equity and convertible instruments, repayment of promoter loan of Rs 495 crore and a net debt of Rs 2,733 crore, as on March 31, 2025. As per the companies' own valuations, the asset has an EBITDA multiple of 5.97x. Furthermore, the company reported revenue of Rs 4,866 crore and adjusted EBITDA of Rs 1,153 crore in FY 2025.

Nabha Power Ltd operates a 1,400 MW (2 × 700 MW) coal-fired thermal power plant at Rajpura, Punjab, with 85 per cent of its generation capacity secured under a 25-year PPA with the Punjab State Power Corporation Limited (PSPCL). In FY 2025, it reported a Plant Availability Factor (PAF) of 95.36 per cent. The plant has long-term domestic coal agreements (5.24 million MT) with SECL and NCL, plus back-up sourcing options. Capable of blending and using both domestic and imported coal, the units have operational flexibility. The units were commissioned in 2014: this means another 13 years of operational PPA remains as of July 2026.

Understanding the valuation

Private corporations invest with the larger objective of generating profits. The willingness of the acquirer to assume the plant's outstanding debt and pay Rs 3,661 crore for its equity reflects confidence that the long-term PPA will generate adequate cash flows to recover the acquisition cost and deliver returns over the remaining contract period. Almost all long-term PPAs have a deemed extension clause of five-10 years depending on the exact terms of the PPA. Coal assets do operate beyond 25 years, with many Indian units operating for up to 40 years, highlighting the overall revenue potential of the deal.

Hypothetically, without a long-term PPA, the same asset would be exposed to merchant market risks, uncertain dispatch and volatile revenues, substantially lowering investor confidence and consequently, its valuation. In a scenario where power purchase is not assured, the transaction will be flagged as risky and revenue generation will vary. The nature of current PPAs eliminate this possibility as the unit will earn revenue based on availability factor, irrespective of actual generation.

Punjab's fertile landmass and agrarian economic base have seen limited success in RE, especially solar installation: the total RE generation is 3.4 GW — just 1.19 per cent of India's RE share. India has not announced any timeline for coal peak, creating no regulatory risk for future operations for the coming decade or more. The limited near-term risk of lower utilisation of assets strengthens investor confidence that the contracted cash flows will continue to materialise.

While RE capacity may rise, the PPA offers an insurance with fixed cash flow, ensuring the business potential of a coal asset takeover. The transaction demonstrates that a long-term PPA is itself a valuable commercial asset. By locking in future revenues through assured capacity payments and contracted power procurement, the PPA significantly enhances the enterprise value of the generating station.

Overall, the assessment demonstrates that PPA lock-in forms an integral component of power system planning and cannot be viewed independently and with discretion. Capacity planning without accounting for the contractual and financial architecture of PPAs risks creating avoidable long-term liabilities and procurement inefficiencies. A comprehensive examination of the existing contractual portfolio ought to be taken up by DISCOMs and power corporations; this can be overseen by the Electricity Regulatory Commissions.

5. Lack of flexibility and emission parameters in existing PPAs

PPAs governing India’s coal-based thermal power plants were developed during a period when coal constituted the dominant source of electricity generation and operated primarily as baseload capacity. Consequently, these contracts were designed to ensure reliable long-term electricity supply, facilitate capital recovery, and allocate commercial risks between generators and procurers.

The rapid expansion of solar and wind capacity has fundamentally altered the operating environment of coal-fired power plants. Increasingly, thermal units are required to cycle more frequently, operate at lower loads, and provide balancing support to accommodate renewable energy generation. However, the contractual framework governing these plants has evolved far more slowly than the power system itself. While existing PPAs continue to provide commercial certainty, they contain limited provisions addressing operational flexibility, efficiency improvements, financial alteration due to flexible operations, or mechanisms that incentivise emissions reduction alongside system reliability.

This chapter examines these gaps from two perspectives. First, it assesses how existing PPAs largely continue to reward plant availability without incorporating operational performance indicators such as efficiency improvements or emission intensity. Second, it identifies contractual rigidities that constrain the adoption of flexible operating practices necessary for higher RE integration. Together, these issues highlight the need to revisit certain contractual provisions so that PPAs continue to support both investment certainty and an evolving low-carbon power system.

Absence of efficiency and emission linkages in PPAs

In 2025, CSE’s analysis of India’s coal-based TPP on efficiency and emission intensity based on CEA’s CDM database version 19 (2022-23) highlighted how, despite a similar GCV fuel range, TPPs performed differently on the two parameters. The thermal units within their technology type also performed differently with vast variance between benchmark performers and others. The variance was observed within similar annual average Plant Load Factors (PLF):

this shows that the variance in performance was linked to operational factors at respective units.

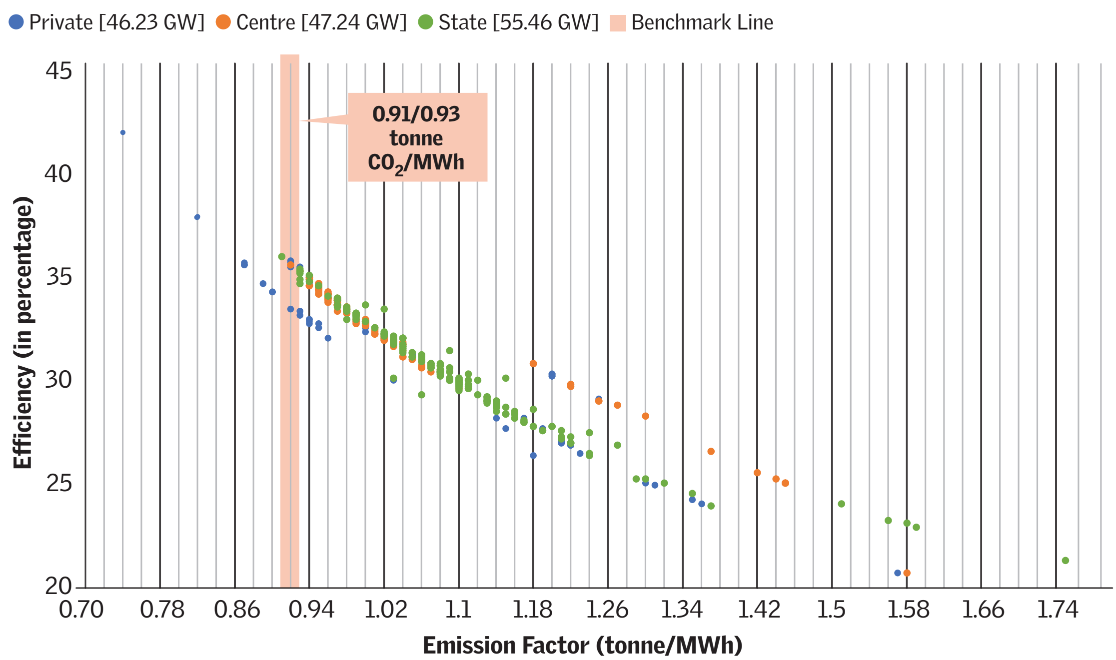
Fleet assessment: Gaps in performance

An assessment of the fleet, divided between subcritical and ultra/supercritical technology on the basis of efficiency and emission factors, exposes the variance in performance of respective units. With 455 subcritical units assessed, one can see the wide variance, with the benchmark emission factor of 0.91-0.92 tonne/MWh not maintained by a majority of the fleet.

Similarly, despite being built from the mid-2010s, the 92 ultra/supercritical units showcase a similar variance in performance.

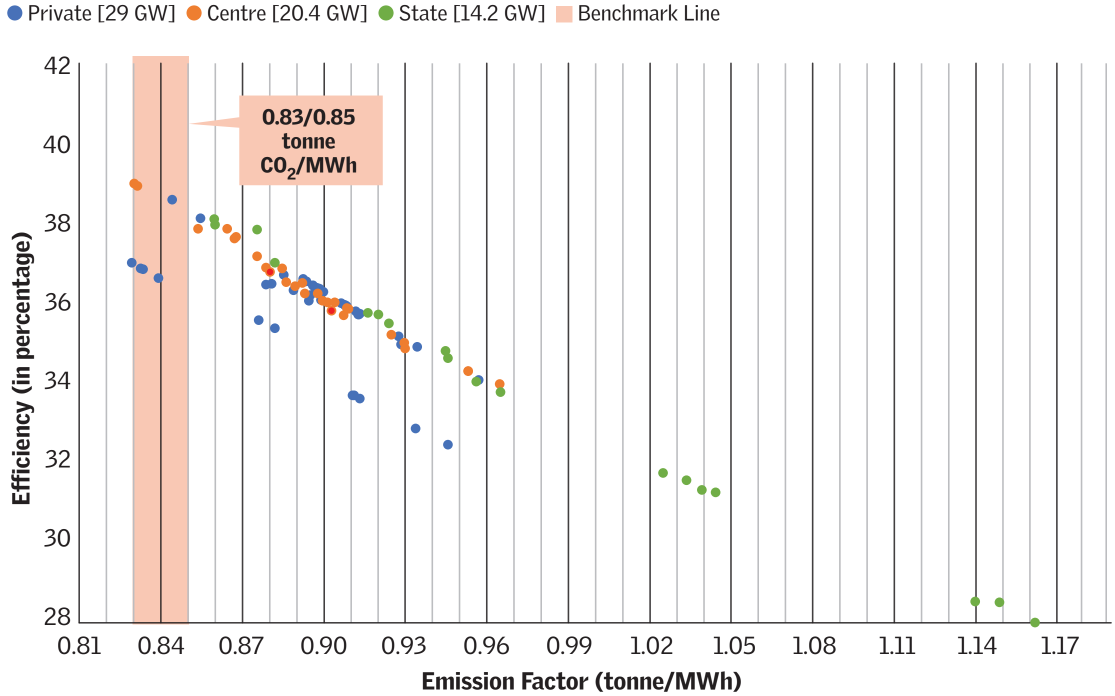
The varying PLF indicates a similar variance in the emission factor, with the benchmark range of 0.83-0.85 CO_2 tonne/MWh rarely seen among the units, despite a higher PLF average.

Graph 10: India's subcritical fleet on efficiency and emission factor [455 units/148.9 GW]



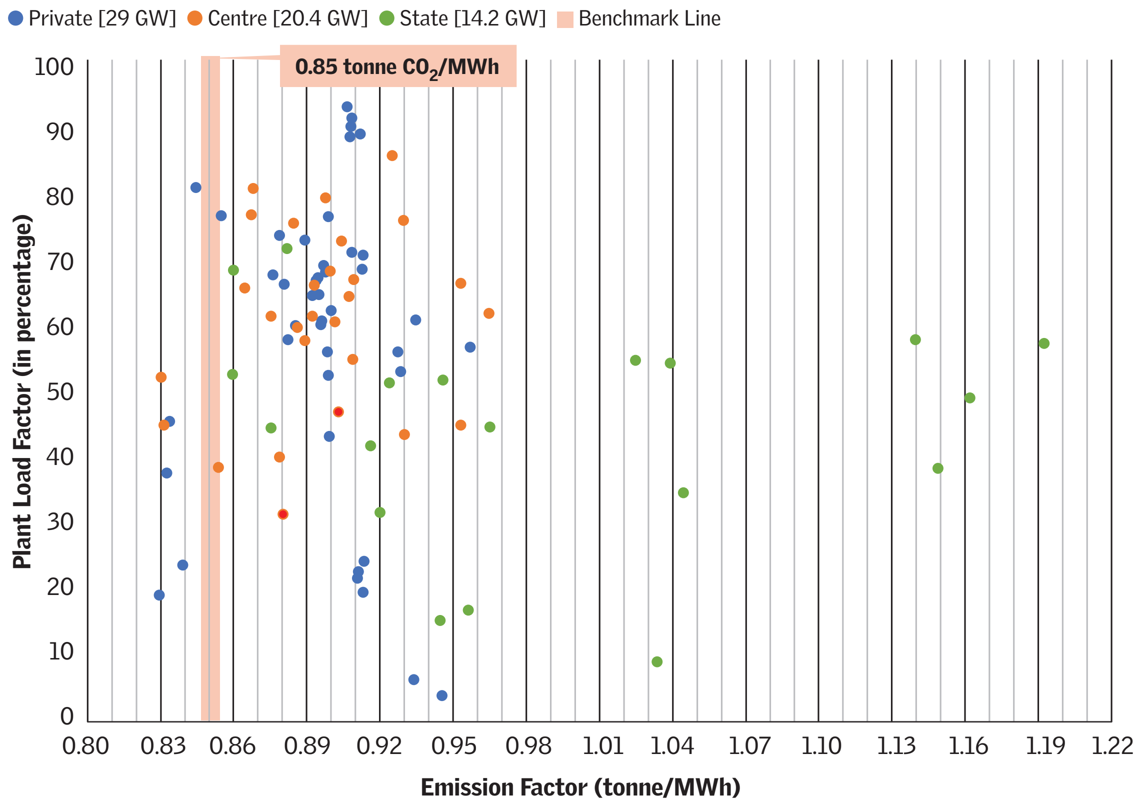
Source: CSE analysis based on CEA's CO_2 database, Version 19

Graph 11: India's supercritical and ultra supercritical fleet on efficiency and emission factor [92 units/63.6 GW]



Source: CSE analysis based on CEA's CO_2 database, Version 19

Graph 12: India's supercritical and ultra supercritical fleet on emission factor and their PLF



Source: CSE analysis based on CEA's CO_2 database, Version 19

Non-recognition of flexible operations

Operational conditions prescribed in the PPAs are primarily centred around the Station Heat Rate (SHR) of a unit and the dispatch alignment as required. Despite RE penetration rising for almost a decade, the PPAs seldom recognise this — this means contractually the unit is not at fault for non-compliance with flexible operational conditions or the systemic costs related to it. The PPAs indicate an 85 per cent universal availability requirement during the day. This is a core issue, as concentrated RE penetration during day-time via solar energy does reduce the overall requirement of coal-based thermal power. In effect, the thermal units are aware that they will operate at lower loads during day-time, and yet will be paid as their contractual obligations are not amended to align with this reality.

PPAs accessed by CSE during this research in 2025-26 have provided a discount in operational parameters to units for lower load operations, with SHR discount available for operating units between 55 to 40 per cent of its rated capacity. Similarly, the default conditions for ramping up or down is set at a threshold of 1 per cent of the unit's capacity, with no incentive to improve the operational conditions. A PPA signed in FY 2025-26, accessed through RTI, showed the discount in performance offered to units operating at lower loads. *Table 8* provides the SHR discount based on the PLF of the unit. The PPA whose data is reproduced was signed recently and hence provided for lower load operations (55 to 40 per cent range). But even after this, the ramping conditions were not upgraded to the 1-3 per cent range.

Implications and learnings

The review of existing PPAs highlights opportunities to better align contractual provisions with the evolving role of coal in the power system. Historically, the

Table 8: Indicative SHR discount at different operational loads

S no	Despatch as proportion of the utility's entitlement in contracted capacity	Increase in SHR % (for supercritical turbine)	Increase in SHR % (for subcritical turbine)
1	85 - 100	Nil	Nil
2	80 - <85	1.8	2.1
3	75 - <80	2.5	3
4	70 - <75	3.3	4
5	65 - <70	4.1	5.1
6	60 - <65	4.9	6.1
7	55 - <60	6	7.6
8	50 - <55	7.1	9.2
9	45 - <50	8.3	11.3
10	40 - <45	9.9	13.8

Source: PPA accessed through RTI disclosure contractual emphasis of PPAs has remained on electricity generation rather than the efficiency or emissions profile of that generation, reflecting the legacy of an era focused primarily on addressing power shortages. As RE penetration increases, availability expectations during solar hours need not mirror those during non-solar hours.

These observations present opportunities to strengthen contractual frameworks while preserving the commercial certainty that PPAs are intended to provide.

- **No operational parameter or incentive for efficiency:** Existing PPAs continue to reward plant availability without incorporating operational efficiency indicators. CSE's *Decarbonizing Coal-based Thermal Power in India* (2025) demonstrated that a significant share of India's thermal fleet operates below the benchmark efficiency expected of its respective technology, with no contractual incentive for improvement.

- **No linkage between efficiency and CO_2 emissions:** PPAs implicitly treat CO_2 emissions as an inherent characteristic of coal-based generation and hence, do not incorporate emission intensity or efficiency-based operational standards. This can create a cycle where inadequate maintenance contributes to lower efficiency, resulting in higher CO_2 emissions per unit of electricity generated without any contractual incentive for corrective action.

- **Limited recognition of flexible operations:** Existing PPAs compensate generators for efficiency losses through SHR discounts during low load operation, but do not establish corresponding operational obligations for flexible operations. While the SHR discount safeguards generator interests under flexible operations, similar contractual recognition of system benefits for procurers remains limited, burdening them with greater system costs. Therefore, the framework recognises the costs of flexibility without defining the corresponding operational outcomes expected in return.

- **Scope for greater operational oversight:** PPAs may incorporate stronger provisions relating to operational monitoring, maintenance standards and periodic technical assessment. Updating operational terms in this manner would help plug existing gaps while unlocking additional decarbonisation potential.

Collectively, these gaps result in avoidable system costs that remain difficult to quantify within existing contractual frameworks. CSE's 2025 report, *Decarbonizing Coal-based Thermal Power in India*, estimated that optimising thermal operations to existing efficiency benchmarks alone can deliver system-wide savings of up to 10-12 per cent. Similarly, differentiating procurement obligations between solar and non-solar hours has the potential to reduce both fixed and variable system costs. Simultaneously, it will create space for DISCOMs to incorporate greater RE into their respective power portfolios. Overall, plugging these gaps represent significant value for an electricity system seeking affordable power, while contributing to the broader decarbonisation of the thermal power fleet.

In conclusion, we can say these gaps do not arise from technological limitations of coal-fired generation, but from contractual provisions that were designed for a different operating paradigm. As the role of thermal power evolves, updating these contractual provisions offers an opportunity to better align plant incentives with contemporary system requirements.

CONTRACTUAL COMPENSATION FOR FSAs — THE GERMAN PAYOUT STUDY

For coal-based thermal power plants, contractual certainty extends beyond the PPA. Long-term Fuel Supply Agreements (FSAs) lock in coal availability over the life of the project, complementing the revenue certainty provided by the PPA and together underpinning the commercial viability of the asset.

The role of FSAs
An FSA is an integral component of a coal-based thermal PPA, as a generating company cannot competitively bid for a thermal PPA without demonstrating long-term fuel security. Historically, coal supply was entirely controlled by Coal India Limited, with competitive bidding for coal mining introduced only in the 2010s. As part of the bidding process, developers are required to specify their fuel source, along with the associated quantity and cost, making the FSA/fuel linkage fundamental to determining both the competitiveness and viability of the bid.

Consequently, the commercial terms of the FSA become embedded within the PPA, linking long-term fuel costs with long-term electricity revenues and creating an additional layer of financial lock-in. This interconnectedness extends beyond the power plant itself, as changes affecting one contract can influence the economics of the other. The discussion on Germany's coal phase-out in this chapter illustrates how compensation frameworks also had to account for coal mines whose operations were contractually and commercially linked to coal-fired power generation.

Germany: Transitioning away the hurdles
In this section, we will take note of the transition undertaken by Germany to understand the long-term risks with respect to coal-based thermal power. Germany had decoupled generation and dispatch, with operations being the sole guaranteed right, unlike in India where the three are still intertwined. The FSA adds a layer to the dynamics that we are exploring here to show that despite not guaranteeing dispatch and generation, the FSA under the PPA creates an operational right that

requires a financial outlay to wriggle out of. The segment on capacity is to showcase the scale of the contractual obligations in Germany.

Historically, as has been the case in other industrialised economies, Germany's power sector has relied on coal for its industrial base — though the announcement of the European Green Deal in 2019 shifted the economic reality for coal-based thermal power operations. The deal commits to a net zero target for the European Union (including Germany) by 2050. In line with the obligation, Germany has passed the Act on the Reduction and Phase-out of Coal-Fired Power Generation *(Kohleverstromungsbeendigungsgesetz)* or the KVBG Act, 2020. As part of the legislation, Germany will phase out coal-based power generation by 2038. This is a tough deadline, similar to a Change in Law effect in Indian regulatory terms.

In 2019, Germany's coal capacity stood at 43.9 GW, comprising 22.8 GW of hard coal and 21.1 GW of lignite capacity. In 2026, total coal capacity has declined to around 28.3 GW, split roughly equally between lignite and hard coal, each accounting for roughly 14-15 GW. A portion of the hard coal fleet (~6.7 GW) has been shifted into the grid reserve (*Netzreserve*), operating only to address system reliability and transmission constraints. Between 2020 and 2025, more than 14 GW of coal capacity has been decommissioned, reflecting a steady policy-driven contraction of the sector.

Table 9: Germany — coal capacity trajectory (2019-2038)

Milestone period	Hard coal max capacity	Lignite max capacity	Combined max capacity
Pre Phase-Out 2019	~22.8 GW	~21.1 GW	~43.9 GW
By end of 2022	15.0 GW	15.0 GW	30.0 GW
By end of 2030	8.0 GW	9.0 GW	17.0 GW
By 2038	0 GW	0 GW	0 GW

Source: Bloomberg - Global coal countdown

Exit payout

The transition away from coal is expensive. Beginning 2021, Germany will be paying a total of €4.35 billion to its two major coal power operators, Rheinisch-Westfälisches Elektrizitätswerk (RWE) in western Germany and LEAG (Lausitz Energie Kraftwerke AG) in eastern Germany.

The compensation amount encompasses the cost of early closure of profitable power assets based on electricity prices and CO_2 emission costs, including incentive payout in instalments. The coal commission arrived at the compensation payout via a negotiated settlement that included the coal operators foregoing their right to sue the government in future over forced market exit. While the overall payout method has been criticised by some, there is consensus over paying corporations for their assets in general.

The common theme of the payout mechanism is the cost of coal mines and their early closure. Coal power plants are accompanied by the FSAs that determine their capacity to reliably generate the obligated electricity. CSE's communication with officials at RWE and LEAG and documents accessed show that the two companies held historical mining rights granted between 1890 and 1920 and recognised under the Federal Mining Act (BBergG), 1982. These guaranteed them a permanent, indefinite right of ownership to the coal extracted. The negotiated settlement includes closure of these assets and their operational value foregone.

iSTOCK PHOTO

Germany's payout covers the cost of closing both the coal mines and the power plants by 2038; Lignite mine and power plant

While compensation to coal plant operators formed one part of Germany's coal exit strategy, the country also recognised that the broader costs of transition extend beyond utilities. Through the Structural Development Act for Coal Regions *(Strukturstärkungsgesetz Kohleregionen),* Germany committed €40 billion to support coal-dependent regions, with €14 billion provided directly to coal-bearing states for economic diversification, local investment and job creation, and €26 billion invested by the federal government in major infrastructure, research institutions and digital development.

Payout methodology

Germany's compensation framework is structured as a staged and differentiated pay-out mechanism combining negotiated fixed payments and conditional, market-linked components. For lignite assets, compensation is concentrated in pre-2030 closures, with RWE receiving approximately €2.6 billion for accelerated closure of western German capacity and LEAG receiving up to €1.75 billion under a two-tier structure comprising a fixed base component and a variable, ex-post market-linked component. For RWE, the payout is in a planned flat-rate compensation explicitly limited to early closures, followed by a regulatory phase-out without compensation from 2028 onwards with no payments provided for lignite assets operating beyond 2030. The hard coal plants are phased out through a reverse auction mechanism which frontloads compensation to incentivise early exit.

Germany implemented compensation for hard coal plant closures through competitive, pay-as-bid auctions under the Coal Phase-out Act, with six auction rounds held since 2020 covering over 10 GW of coal capacity. While the initial rounds were competitive, the last three of the four most recent auctions were undersubscribed, leaving around 700 MW of the targeted capacity unawarded. However, energy security concerns following the energy crisis led Germany to temporarily allow several previously retired coal plants to return to operation, highlighting the challenges of balancing coal phase-down commitments with system reliability. Reduced competition in the later auction rounds also meant that successful bids were awarded at the maximum permissible compensation, increasing the government's transition costs. Inadvertently, the compensation structure resulted in larger units with higher efficiency to close down first as operators were worried about their inability to recoup costs at a later stage. The design flaw affected the overall CO_2 reduction in the near term.

LEAG's lignite portfolio, located in the Lusatian and Central German regions, follows a more gradual and staggered closure pathway extending to 2038. Its compensation framework, operates under a two-tier model capped at €1.75 billion. This includes a guaranteed base component of €1.2 billion to cover fixed costs, alongside a variable component of up to €550 million. The variable portion is determined through an ex-post market-based calculation at the time of plant closure.

Insights for the Indian context

India's energy transition will add more coal power in the near future and therefore, avoiding risks that lead to long term state payout is the key takeaway from Germany. The combined effect of property-like mining rights and long-term regulatory planning produces similar economic constraints to India's long-term PPA structures. The inherent linkage of FSA within the PPA highlights the dual asset under them, creating barrier to any downward revision in the coming years.

The deemed tenure extension of mining leases along with baseload contractual terms risks greater systemic costs for underutilisation of coal plants. With day-time operations being limited to 55 per cent and expected to fall to 40 per cent in the coming years, the overall coal usage will drop. Contractual agreements need to recognise this to prevent higher upward cost recovery via tariffs or lumpsum claims. Furthermore, avoiding reliance on contractual revenue guarantees prevents the downward cost lock-in that DISCOMs face owing to contractual obligations leading to financial burden on public exchequer.

6. Revisiting PPAs?

Long-term PPAs are founded on the principle of contractual certainty, providing a stable framework for allocating rights, obligations, revenues and risks over the life of a project. At the same time, PPAs are commercial agreements between contracting parties. While they do not generally prescribe a formal process for renegotiation, neither do they inherently prevent mutually agreed changes, subject to the applicable legal and regulatory framework.

The preceding chapters identify how evolving system requirements, particularly RE integration and the need for greater thermal flexibility, have exposed contractual gaps that were not envisaged when most existing PPAs were signed. This naturally raises the question of whether long-term PPAs can evolve to accommodate these changing circumstances while preserving the certainty on which they are founded. We have noted their system-wide lock-in and the additional costs they create for power procurers. Furthermore, the lack of decarbonisation focus puts them out of sync with the larger environmental goals underpinning the foundation of RE introduction in the first place.

This chapter examines that question from two perspectives. It first explores the rationale for revisiting existing contractual provisions in light of changing commercial and operational realities. It then examines practical pathways for incorporating these changes, both in existing PPAs through mutually agreed amendments and in future PPAs through revised contractual design.

Systemic need for change

Today, RE is greater than fossil-based power capacity, and this has altered the generation mix permanently. Since FY 2013-14, installed solar energy capacity has grown from 2.6 GW to 150.6 GW in FY 2025-26, a whopping 57-fold increase. In FY 2019-20, India generated approximately one unit of solar electricity for every 19 units of coal generation. By FY 2025-26, this ratio had improved to one unit of solar for every 7.3 units of coal generation, representing a 2.6-fold increase in solar's contribution relative to coal generation over the period.

Solar's contribution to India's total electricity generation also increased significantly, rising from 3.6 per cent in FY 2019-20 to 9.5 per cent in FY 2025-26. While coal's share of total generation has remained broadly stable at around 69 per cent, the rapid growth of solar generation has fundamentally altered coal's operational role within the power system, particularly during daylight hours when solar output is at its peak. India's battery storage capacity is limited with only three GWh on system as of FY 2025-26, showcasing that majority of the solar energy is consumed during the solar hours.

Although the power generation mix has changed substantially, existing PPA provisions have remained largely constant, resulting in availability-based payments for thermal capacity even during periods when renewable generation reduces the need for its dispatch. The need will reduce further, with CEA's Long-term Resource Adequacy Plan, 2035-36 being foundationally based on operating coal-based thermal power at its existing minimum technical load (MTL) of 55 per cent. This is complimented with the larger Flexible Operation Phasing Plan 2023 targeting a reduction of MTL to 40 per cent for four-fifth of the coal power fleet. In July 2026, despite monsoon onset, solar generation on select days has maintained its 16-18 per cent daily generation share showcasing the high availability of solar power in general.

Estimating daytime surplus thermal capacity

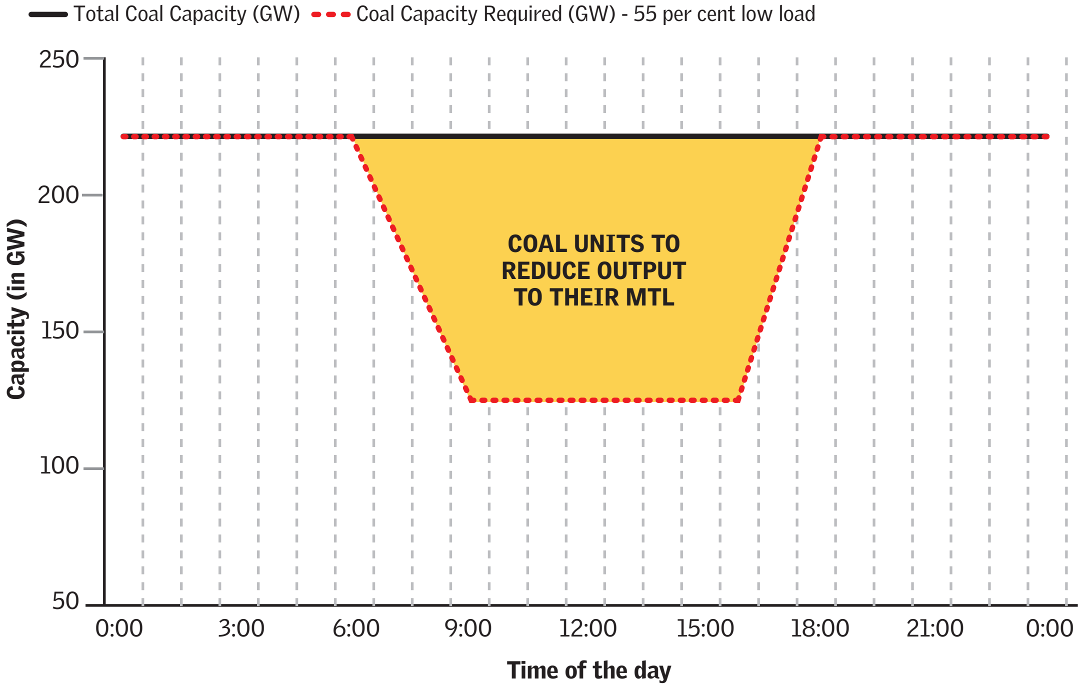
In FY 2025-26, the installed capacity for coal based thermal power stands at 228.6 GW. With the increasing penetration of solar generation, the operational requirement of this fleet varies significantly during daylight hours. Assuming a representative operating profile, solar generation is considered to reach its peak between 9:00 AM and 4:00 PM, allowing coal units to reduce output to their MTL while remaining available for system support. For our calculations, we have relied on the installed capacity of the coal power fleet to showcase the systemic change.

Under the current fleet-wide MTL of 55 per cent, the operational requirement of the coal fleet reduces to 125.73 GW, leaving an estimated 102.87 GW of contracted coal capacity available but not required for generation during peak solar hours. This daytime surplus is illustrated by the shaded area in *Graph 14*.

If the fleet-wide MTL is reduced to 40 per cent, the operational requirement falls further to 91.44 GW, increasing the estimated daytime surplus to 137.16 GW.

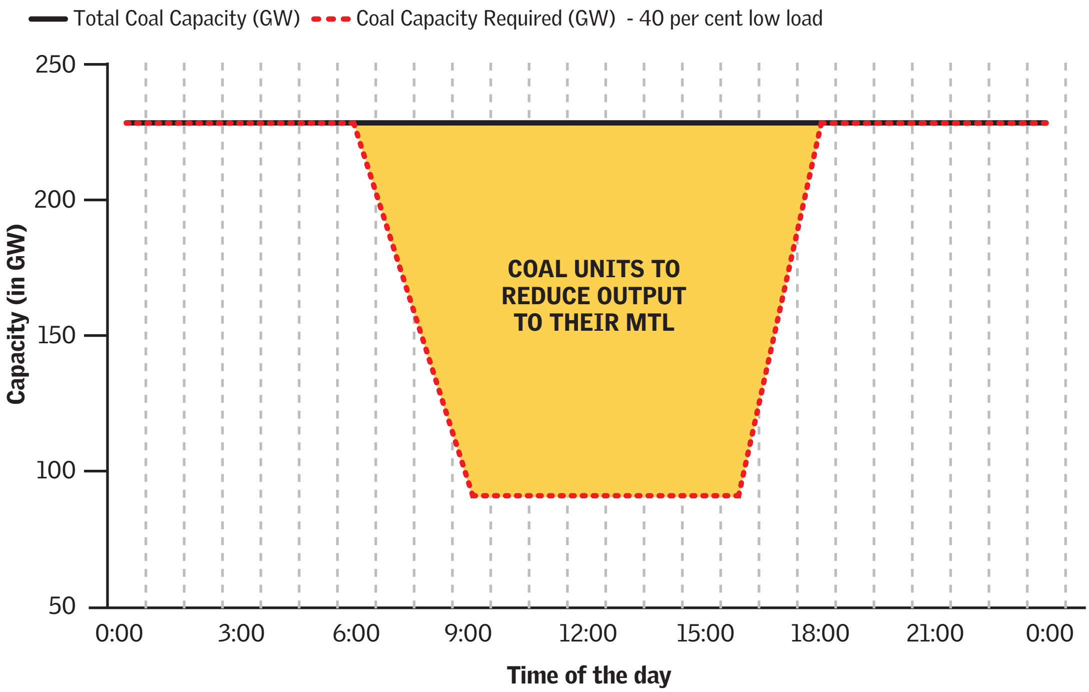
Under assumptions that 10 per cent of the installed capacity is consumed as auxiliary power and 15 per cent of the fleet remains unavailable due to planned outages and maintenance, the estimated daytime surplus remains substantial. Not all the capacity is available every day and units utilise a share of the power generated for their own use before dispatch.

Graph 13: Illustrative operation of coal fleet at 55 per cent MTL



Source: CSE analysis

Graph 14: Illustrative operation of coal fleet at 40 per cent MTL



Source: CSE analysis

Table 10: Net daytime solar power surplus

Scenario	Installed capacity (GW)	Gross surplus (GW)	Deduction: Auxiliary (10%) + outage (15%) (GW)	Net surplus (GW)
55% technical minimum load	228.6	102.87	57.15	45.72 GW
40% technical minimum load	228.6	137.16	57.15	80.01 GW

After accounting for these factors, the surplus coal capacity during peak solar hours is estimated at 45.72 GW under the current 55 per cent MTL, increasing to 80.01 GW at a 40 per cent MTL across the fleet. Since reserve capacity remains part of the operational fleet to maintain system reliability, it is not deducted from these estimates.

These estimates are illustrative and intended to demonstrate how increasing solar generation changes the operational requirement of the coal fleet. While this capacity continues to provide system reliability and evening ramping support, it also highlights the extent to which existing PPAs continue to remunerate thermal capacity based on availability even when daytime dispatch requirements are substantially lower. This evolving operational reality strengthens the case for differentiated contractual provisions that better reflect the changing role of coal in a renewable-rich power system.

PPA renegotiations — an unexplored alternative

A PPA is, fundamentally, a contractual agreement between two parties, and its terms can be modified where the parties mutually agree to do so, subject to the applicable legal and regulatory framework. The law does not, in itself, prevent parties from revisiting their contractual arrangements. In practice, however, PPAs are rarely reopened because a material change in circumstances can alter the balance of the contract, making renegotiation difficult where the resulting commercial benefit or burden falls disproportionately on one party. The experience so far has largely been one of renewable energy creating a systemic change in the power system while leaving procurers bound by long-term contractual commitments. The default response is to benefit off the other party causing systemic delays that favour no one and cause legal costs that go unreported.

To examine whether the contractual rigidity is necessarily permanent, the case of Tata Mundra UMPP provides a useful counterpoint. Over nearly two decades, the project has moved through a significant change in its underlying commercial assumptions, financial distress, prolonged periods of low utilisation and eventual renegotiation of its PPA. The journey demonstrates that contractual change can be pursued through negotiation rather than necessarily beginning with a legal dispute. It also establishes a broader principle, where market or economic conditions materially change, renegotiation can remain an available route for both parties to realign the contract.

In Mundra, the trigger was a change in Indonesian coal pricing regulations. Today, the changing power system is being driven increasingly by RE. The circumstances are different, but the underlying consideration is the same. The possibility of revisiting existing PPAs when the market and system conditions on which they were built have changed.

Renegotiating a PPA: The story of TATA Mundra UMPP

The question is not whether a PPA can ever be amended, but under what circumstances parties may find it commercially necessary to revisit its terms. The case of TATA Mundra UMPP shows when the scale of balance shifts towards DISCOMs from the power generators. India's first UMPP commissioned between 2012 and 2013, consists of five supercritical thermal units of 800 MW each. Power generator TATA Power signed the PPA under Section 63 of the Electricity Act. The original PPA dated April 22, 2007 with the DISCOMs allocated its generation to the states of Gujarat (1,900 MW), Maharashtra (800 MW), Punjab (500 MW), Haryana (400 MW) and Rajasthan (400 MW). The levellised tariff under the competitive bidding process for the project was Rs 2.26 per unit.

The power generator's commercial viability to operate at these costs was based on the sourcing of coal from Indonesia. However, the project economics was negatively impacted after a change in Indonesian regulations in September 2010. Indonesia aligned the export price of coal with international market prices, a stark deviation from the previous pricing regime followed in the country for a period of 40 years. This meant that independent of the source cost of coal in Indonesia, export of the resource had to be aligned to international market rate, raising the cost of operation and eroding operational profit of the project.

Refusal by courts

Coastal Gujarat Power Limited (CGPL), TATA Power's wholly owned subsidiary operating the Mundra UMPP, approached state-owned DISCOMs for tariff renegotiation citing the change in economic reality. These negotiations brought no fruit and the company approached the CERC under the available remedy of the existing PPA, i.e. change in law and *force majeure*.

In 2017, after appeals against the decisions of CERC and APTEL for compensatory tariff as limited relief to the power generators were challenged, the case reached the Supreme Court of India. On April 17, 2017 the court opined in the seminal judgement of *Energy Watchdog & Ors. vs. Central Electricity Regulatory Commission & Ors.*, that,

The meaning of the expression "change in law" in clause 13 cannot depend upon whether coal is sourced in a particular PPA from outside India or within India. The meaning will have to remain the same whether coal is sourced wholly in India, partly in India and partly from outside, or wholly from outside.

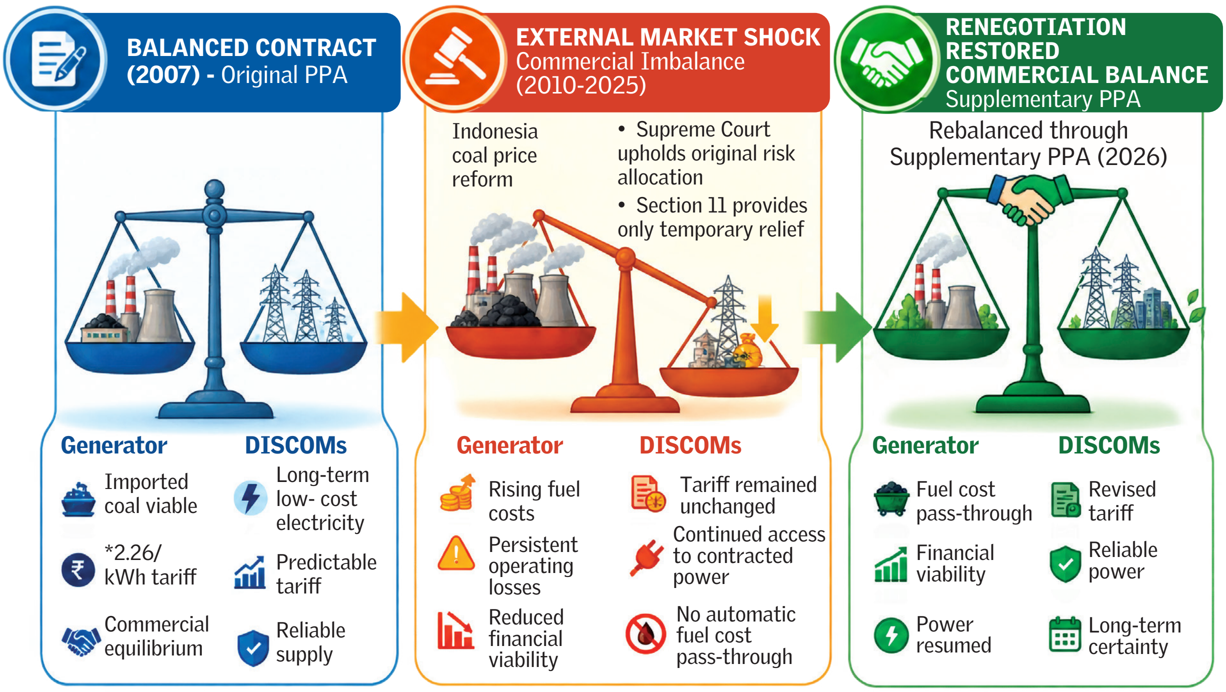
The court rejected the plea of the power generators that the policy change in Indonesia amounted to a change in law within the Indian context, stating that the original PPA was not signed on the condition of procuring coal from Indonesia only. On the *force majeure* front, the court stated that price of coal was part of the commercial risk the supplier agreed to from the outset and increase in price of coal cannot be an excuse to invalidate the contract. The impact of the judgement could be seen in the financial losses reported as by 2017 the accumulated losses amounted to Rs 6,457 crore against the total paid-up equity capital of Rs 6,083 crore.

Temporary reprieve of Section 11

Section 11 of the Electricity Act vests the government with extraordinary powers to direct generating companies, including thermal power plants, to operate their stations in the public interest during exceptional situations such as natural disasters, threats to national security, or other circumstances. These directions are intended to ensure reliable electricity supply and prevent power shortages during emergencies. Since complying with such directions can increase the costs incurred by generators, Section 11(2) allows the appropriate commission to provide financial relief by compensating them for the additional costs.

Since the COVID pandemic, the section has offered limited temporary relief to the UMPP with power demand growth leading to utilisation of this extraordinary power by the government until June 2025. The power plant operated at reported annual PLF of 25 per cent, 32 per cent, 56 per cent and 65 per cent between FY 22 and FY 25. Since July 2025, the units were in extended reserve maintenance to avoid operational losses.

Figure 5: TATA Mundra UMPP — the trajectory



Source: CSE analysis

Supplementary PPA success

In March 2026, TATA Power announced in its regulatory filings that the company had inked a Supplementary PPA with state of Gujarat resuming power generation for the unit. As per the public information, the agreement allows for a full coal cost pass through. That means the variable cost of power generation that largely depends on the price of imported fuel will now be passed onwards, resulting in the upward revision of tariff. The final regulatory approval is awaited on the PPA as of July 2026. The company in its latest filings of FY 2026 stated that the template of supplementary PPA will be model for signing similar agreements with the other four states with a target deadline of September 2026.

According to NITI Aayog's *India Climate & Energy Dashboard*, in FY 2024-25 the state of Gujarat purchased electricity from Mundra UMPP at a total cost of Rs 4.95/kWh with a variable price component of Rs 4.04/kWh with the rest being fixed costs. In comparison, NTPC Kudgi, a similarly sized 800-MW TPP using domestic coal and commissioned between 2016-2018, supplied electricity to the state of Karnataka at a total cost of Rs 7.50/kWh, with a variable price component of Rs 4.96/kWh and the rest being fixed costs.

The experience of TATA Mundra provides a useful case to examine PPA renegotiation. The supplementary PPA showcases the capacity of DISCOMs and power generators to redefine the PPA based on their mutual agreement based on altering commercial realities. Despite Mundra UMPP being a Section 63 plant, the parties were able to negotiate a 'cost pass through' — that is, an alteration in the primary nature of the allocation.

This is also a cautionary tale, as the delay of 15 years highlights the fact that by not including this as a default mechanism, the forced costs can lead to disproportionately high negative impact. In conclusion, the case showcases that RE integration into DISCOM's power planning is not absolutely inhabited by their existing PPAs with negotiated amendments a possibility to prevent future cost lock-ins.

Change in law

The state also possesses the capacity to uniformly implement an amendment with a Change in Law provision of the Electricity Act. The extraordinary power has been utilised in bringing environmental and operational changes in power sector governance over the years. It is provided as a standard provision in long-term PPAs that allocates the financial risk arising from changes in government policies, laws or regulations after the contract has been awarded. Rather than preventing governments from introducing new regulations, the provision ensures that if such changes increase or decrease the cost of supplying electricity, the affected generator is restored to the same economic position it would have been in had the regulatory change not occurred.

Under the Indian Model PPA, the financial risk of regulatory changes is largely allocated to the power procurer. Where a Change in Law event results in additional costs for the generator, the Appropriate Electricity Regulatory Commission determines the compensation required, which is typically recovered through adjustments to the tariff payable by the utility. In effect, the commercial impact of regulatory changes is passed through to the procurer while ensuring that the generator continues to recover its legitimate costs.

This provision provides an important pathway for contractual evolution. Governments can introduce new operational requirements for coal-based thermal power plants, such as flexibility standards, revised efficiency norms or other performance requirements and the resulting increase in operating costs may qualify as a Change in Law event. Instead of requiring the contract to be terminated or remain commercially unviable, the PPA provides a mechanism to rebalance its economics through tariff adjustments or mutually agreed amendments. In this

CONTRACTS FOR DIFFERENCE (CFDS) — AN ALTERNATIVE

Changing power markets raise the question of whether future contracts need to be structured differently from the outset. Contracts for Difference (CfDs) represent a different approach to providing revenue certainty in electricity markets. Unlike a conventional PPA, where the buyer agrees to purchase electricity under predetermined contractual terms, a CfD is a financial contract. The generator sells electricity into the wholesale electricity market at the prevailing market price, while a parallel financial settlement compensates the generator whenever the market price falls below an agreed strike price. Conversely, if market prices exceed the strike price, the generator pays the difference back. In this manner, the CfD separates physical electricity dispatch from revenue certainty, allowing electricity to be dispatched based on market conditions while providing investors with stable revenues.

The increasing adoption of CfDs reflects the changing nature of modern electricity systems. Traditional PPAs were developed for power systems dominated by large baseload thermal plants operating under predictable demand conditions. As RE penetration has increased, wholesale electricity prices have become more volatile, making long-term revenue certainty more difficult to achieve through conventional market participation alone. CfDs address this challenge by reducing market price risk while allowing generators to respond to real-time dispatch signals. Consequently, several jurisdictions have adopted CfDs as a preferred mechanism for supporting investment in RE.

However, CfDs also have important limitations. Unlike conventional thermal PPAs, they do not inherently provide assured capacity payments or guarantee physical availability of generating assets during periods of system stress. Moreover, the financial support required to bridge the difference between market prices and strike prices is ultimately borne by governments or electricity consumers, raising affordability concerns if strike prices are set too high or wholesale market prices remain persistently low. For these reasons, CfDs are generally viewed as a market-based complement to electricity market reform rather than a direct substitute for long-term coal-based PPAs, particularly in systems where affordability and supply security remain primary policy objectives.

While CfDs illustrate how long-term contracts can evolve to accommodate changing electricity markets, the recommendations in this report focus on reforming India's existing coal PPAs rather than replacing them with an alternative contracting model.

way, the Change in Law provision preserves both contractual certainty and the government's ability to introduce reforms that respond to changing power system requirements.

The challenge of effecting the gaps highlighted via change in law is that not all units will be impacted. A coal unit operating efficiently with good maintenance practices may not require additional cost, but an incentive in schedule. Similarly, units that have not maintained properly over the years, providing extra costs will have a negative reward impact. Therefore, the change in law use will have to be coupled with a detailed mechanism for cost, to avoid negative incentives.

Overall, it is a top-down mechanism. The implementation of reforms depends on governments issuing new regulations, their subsequent adoption by the respective Electricity Regulatory Commissions, and individual generating stations seeking approval for tariff adjustments. The phased implementation of the CEA Flexible Operation Phasing Plan, 2023 and the gradual alignment of State ERC regulations illustrate that this process can be time-intensive.

The imperative to renegotiate

Renegotiation offers a more immediate and collaborative pathway. By mutually agreeing to amend commercial or operational terms, generators and procurers can respond to changing system requirements without waiting for regulatory interventions. Regulatory provisions and judicial precedents can continue to guide the process and resolve disputes where necessary, but negotiated amendments provide a faster and more practical route for aligning existing PPAs with the evolving needs of the power system. The need for such a mechanism is evident from the contractual profile of India's coal fleet.

Our analysis of RTI data over PPA lock-in for select states shows that the majority of India's coal-based thermal power plants have signed on for long-duration PPAs. Given that a substantial share of India's coal PPAs will remain in force for another one to three decades, relying solely on contract expiry would significantly delay the operational reforms required for renewable energy integration. The current build-up continues towards a similar trajectory. More importantly, it lacks the necessary transition reality of the power system that has altered the operational profile of coal units, especially during day-time hours. Consequently, contractual provisions continue to reflect the operational assumptions of the past rather than the requirements of an increasingly renewable-rich power system.

Yet, PPAs are not a finality, and can undergo changes. The Ministry of Power has periodically revised the Model PPA to reflect evolving policy priorities, demonstrating that contractual design itself continues to evolve. Furthermore, the TATA Mundra case showcases the capability of modifying PPA even under section 63 units. This provides the precedent for mutually negotiated modifications.

India's power sector is in a unique state to make this change, as the majority of its coal capacity is government-owned or operated. As per the CEA's *CDM CO_2 database, Version 21 (2024-25)*, 66 per cent of the installed coal power capacity is owned by the Central or various state governments. Currently, 70-80 GW of coal capacity is privately operated (discounting the newly constructed ones).

The predominance of public ownership significantly lowers the coordination barriers associated with renegotiation. Since the principal contracting parties are government-owned entities, operational reforms can be pursued through negotiated amendments with relatively limited commercial conflict compared to markets dominated by private ownership.

7. Model Clauses for Thermal PPAs

The core purpose of this chapter is to pinpoint the regulatory changes that can be added into model PPAs from the perspective of power corporations/DISCOMs to balance the RE integration and decarbonisation potential. Over the course of the earlier chapters, we have showcased the need to reform thermal PPAs to help them align with the shift of the coal-based thermal power sector from baseload operations to flexible power resources for the energy grid. The clauses are mere suggestions to act as starting points for discussions around the inclusion of similar clauses in thermal PPAs.

Definitions to be included

- **Efficiency**: Calculated annually, shall measure the net electricity generated in proportion of thermal energy contained in coal used by the generating unit. It is measured in percentage terms with higher value indicating greater efficiency of fuel conversion into electricity.

- **Emission intensity**: Calculated annually, the emission factor measures the carbon intensity of electricity generation by relating total CO_2 emissions to the net electricity generated by the unit. Shall be expressed in tonnes of CO_2 per MWh, with lower values indicating lower emissions per unit of electricity generated.

- **Flexible operations**: The ability of a coal-based thermal generating unit to generate electricity at different output levels, including repeated increase and decrease in generation, within the limits specified by CEA regulations as required for reliable grid operations.

- **Low load operations**: The ability of a coal-based thermal generating unit to operate stably at its minimum technical load, as declared by the unit or prescribed under the applicable CEA regulations, whichever is lower, without the use of secondary oil for flame stabilisation.

- **Non-solar hours**: The hours other than the notified solar hours, as specified under the applicable regulations or by the system operator for the purpose of grid scheduling and operation

- **Ramp rate**: The rate of change of output power, expressed in percentage of maximum continuous power rating, per minute, as declared by the unit or prescribed under the applicable grid regulations, whichever is higher.

- **Solar hours**: The period of the day, as notified by the system operator or prescribed under the applicable regulations, during which solar energy generation is expected to be available and contribute to meeting grid power demand.

Suggestive clauses to be included

- **Seller's obligations**:
    - o operate unit in line with the declared efficiency of the unit relying on best available operation and maintenance practices to maximise fuel savings

    - o declare emission intensity of generated electricity on a quarterly basis to the buyer

- **Buyer's obligations**:
    - o Provide optimum schedule for maintenance of unit to maintain consistent efficiency and emission intensity of generated electricity
    - o Maintain record of efficiency and emission intensity of generated electricity on a quarterly basis

- **Energy charge**:
    - o Subject to regulatory foresight the parties may agree to a differentiated charge for solar and non-solar hour of operations with provision for seller to sell excess power in open market during solar hours without sharing sale profits with the buyer

    - o Subject to regulatory approval, the parties may agree to a variation in energy charge during low load operations to account of SHR loss during lower PLF conditions

    - o Subject to regulatory approval the parties may mutually agree to an emission factor range for electricity generated with incentive payout on tariff accrued to seller if generated electricity is aligned to the agreed upon range

- **Tenure of agreement:**
  - o The Parties may mutually agree to amend the tenure of this Agreement where a substantial shift in the generation mix, including the availability of renewable energy at significantly lower tariffs than the prevailing energy charge under this Agreement, materially reduces the requirement for the contracted capacity. *Provided*, where such amendment results in the early termination of the Agreement, the Parties may agree upon a mutually negotiated compensation amount, which may include unrecovered investments and other legitimate costs, but shall exclude compensation for foregone profits/windfall gains.

- **Termination**:
  - o The Parties agree that the introduction of any law, regulation or regulatory direction requiring the generating station to undertake retrofits, modify its operational parameters, or implement measures to facilitate renewable energy integration and flexible operation shall not, by itself, constitute a ground for termination of this Agreement. The Parties shall endeavour to address the resulting commercial implications through mutually agreed amendments or the applicable regulatory mechanisms.

- **Environmental compliance**:
  - o The Parties shall ensure that the generating station operates in compliance with all applicable environmental laws, regulations and statutory approvals, while undertaking reasonable measures to ensure compliance towards agreed operational efficiency range close to benchmark industry performance and reduce the emission intensity of electricity generation in accordance with the terms of this Agreement.

The concept of scheduled exit/release clause

Long-term PPAs may incorporate a scheduled exit/release clause that specifies, at the time of contract execution, the compensation payable in the event of an early termination at predetermined milestones during the tenure of the agreement. Rather than determining the valuation only when renegotiation arises, the Parties would mutually agree upfront on the cost of exiting the contract after specified periods, such as the 5^{th}, 8^{th}, 12^{th}, 15^{th}, 20^{th} and 25^{th} years.

Such a provision would improve commercial transparency by revealing the value attributed to the remaining contract at different stages of its life. As power systems evolve with increasing RE penetration, technological advancements or changing environment-related considerations, both procurers and generators would have greater certainty regarding the financial implications of restructuring or exiting the agreement. The predetermined valuation would also discourage the overpricing of assets, as developers would be required to disclose and agree upon the cost of an early termination at the outset of the contract.

Predetermined buy-out and exit clauses are common across commercial agreements in sectors such as infrastructure, private equity, mergers and acquisitions, and long-term service contracts. Much like existing PPAs specify SHR discounts for operation at lower plant loads, a scheduled exit/release clause will provide procurers with advance visibility of the financial implications of terminating or restructuring the contract. This will transform future renegotiations from uncertain valuation exercises into commercially predictable decisions, thereby reducing systemic lock-in costs while preserving contractual certainty.

8. Key Findings

The findings presented below consolidate the principal analytical outcomes of this study. Together, they reaffirm the central premise of the report — India's long-term thermal PPAs, while successful in enabling capacity creation and investment certainty, now require contractual evolution to remain aligned with the changing realities of the power system.

- **PPA categorisation blind spot:** India's regulatory threshold classifies any agreement exceeding five years as a "long-term PPA". This creates a major structural flaw by cataloguing contracts marginally over five years in the same category as 25-year contracts, obscuring the massive differences in capital recovery exposure, multi-decade fossil lock-ins, and system planning risks.

- **Longterm lock-in *via* PPAs — what RTI data reveals:** RTI assessment mapped 67.1 GW of contracted coal-based thermal capacity across public sector DISCOMs and power corporations that responded. RTI applications submitted between January and March 2026 in 12 states yielded the following responses:
    - *Six full disclosures*: Haryana, Karnataka, Kerala, Maharashtra, Rajasthan and Tamil Nadu
    - *Two partial disclosures*: Madhya Pradesh (three DISCOMs) and Uttar Pradesh (four DISCOMs)
    - *One rejection*: Bihar's DISCOMs (SBPDCL and NBPDCL) rejected the applications
    - *Three no responses*: Assam, Chhattisgarh and Jharkhand provided no response

The assessed PPAs remain overwhelmingly long-term (25 years), with the largest concentration of contracted capacity expiring in the 2030s. Among the surveyed portfolio, 2035 alone accounts for nearly 15.7 GW of contracted capacity, followed by 2028 (7.2 GW), 2032 (6.7 GW), 2031 (6.2 GW) and 2034 (6.0 GW).

- **Lower utilisation cost trap:** Dynamic grid integration and mandatory daytime ramping down to MTL may cause a typical 660 MW unit's lifetime output to collapse from 115.43 TWh to 73.58 TWh. This leaves ~36 per cent (41.85 TWh) of generation potential unutilised, inflating system costs as fixed cost obligations are spread across fewer units of generated electricity.

- **Power procurement exception:** BEST (Maharashtra) stands out as the sole entity utilising flexible five-year short-term thermal PPAs. Unlike most surveyed utilities, BEST procures coal power from existing generating stations, demonstrating that continued operation of ageing coal units is commercially feasible without entering into new 25-year contractual commitments.

- **The PPA tenure trade-off (saving illusion *vs* doubled liability):** The CSE analysis of a benchmarked 800 MW unit shows that extending the PPA tenure from 11 to 25 years reduces the minimum capacity tariff by roughly 70 to 114 paise/kWh (from Rs 4.28/kWh down to Rs 3.14/kWh). However, this minor annual reduction more than doubles the cumulative minimum consumer payout from Rs 32,968 crore (11 years) to Rs 54,966 crore (25 years) due to compounded debt interest and prolonged return on equity payouts. At the market weighted tariff, 25-year payouts reach Rs 67,500 crore against the total CAPEX cost of Rs 10,400 crore.

- **The "toll-gate" effect:** Although project debt is typically retired within 10-12 years, DISCOMs continue paying fixed-capacity charges for the remaining contract period, allowing equity returns to continue accruing well after the underlying capital investment has largely been recovered. This transforms the generator into a "rentier" or "toll-gate" that collects full capacity charges to provide power to the buyer.

- **Fixed cost payout multiples over a longer duration:** Under a 25-year PPA for 2,400 MW, a project with an estimated capital cost of Rs 27,600-31,200 crore would receive approximately Rs 1.75 lakh crore in fixed revenue payments over the contract period, equivalent to 5.6-6.4 times the initial capital investment under availability assumptions.

- **Cautionary tale of embedding FSA with PPA — Germany's € 4.35 billion payout model:** FSAs create a second layer of contractual lock-in beyond the PPA. Since long-term fuel security is a prerequisite for bidding thermal PPAs, the commercial terms of the FSA become embedded within the PPA itself. Germany negotiated € 4.35 billion in targeted payouts (€ 2.6 billion to RWE and € 1.75 billion to LEAG) alongside € 40 billion in regional structural funds to compensate for foregone mining rights and early asset closures. The negotiated compensation framework recognised not only the early closure of coal-fired power stations, but also the commercial value of coal mining assets contractually linked to electricity generation, illustrating the broader financial implications of interconnectedness.

- **Substantial daytime surplus coal capacity:** Installed solar capacity grew 57-fold from 2.6 GW (FY 2013-14) to 150.6 GW (FY 2025-26), resulting in one unit of solar being equivalent to seven units of coal power in this FY from an earlier ratio of 19 units of coal power in FY 2019-20. This alters the need for coal-based power during solar hours — the CSE analysis shows that at the current fleet-wide MTL of 55 per cent, approximately 102.87 GW of contracted coal capacity remains available but not required during peak solar hours. Even after accounting for auxiliary consumption and planned outages, the estimated surplus remains 45.72 GW**.** This rises further to around 80 GW if the fleet attains lower MTL of 40 per cent.

- **PPA renegotiation as plausible:** The Tata Mundra UMPP demonstrates that long-term PPAs can be commercially renegotiated. Despite the project being awarded under Section 63 through competitive bidding, the parties executed a Supplementary PPA in March 2026 introducing a full coal cost pass-through, reaffirming that mutually negotiated amendments remain a viable pathway for adapting PPAs to altered commercial circumstances. While Change in Law provisions enable tariff rebalancing following regulatory changes, their implementation depends on successive regulatory actions and approvals. In contrast, mutually negotiated amendments can respond more quickly to evolving operational requirements.

9. Recommendations

The recommendations presented below complement, rather than replicate, the illustrative contractual clauses proposed in earlier in the report. The recommendations aim to provide broader policy and institutional actions that can support the gradual evolution of India's thermal PPA framework in line with the findings of this report.

- **Update the model PPA:** Revision of the Model Thermal Power PPA by the CERC and the MoP ought to reflect the evolving role of the coal-based thermal power sector. Revised/reformed PPAs should incorporate provisions relating to operational efficiency, emission intensity, flexible operations, differentiated dispatch during solar and non-solar hours, and structured mechanisms for contract review over long tenures.

- **Make periodic PPA portfolio review mandatory:** DISCOMs and power corporations should periodically undertake a portfolio-wide review of their existing thermal PPAs to assess long-term contractual liabilities against evolving system requirements. The review should evaluate the commercial viability of continuing existing contracts *vis-à-vis* alternatives such as renegotiation, tenure revision or negotiated exit, based on a comprehensive cost-benefit assessment.

- **Establish a framework for PPA renegotiation and exit:** Given that a large share of India's coal fleet will remain under long-term PPAs for another one to three decades, the CERC and SERCs should establish standard principles and model provisions for voluntary renegotiation, tariff adjustment and negotiated exit, including clear treatment of unrecovered investment of existing and new contracts. Any compensation should be limited to genuine unrecovered costs and avoid the inclusion of windfall future profits.

- **Apply a strict system-need and least-cost test for PPAs:** Regulatory approvals for new long-term PPAs ought to demonstrate a clear need for additional contracted power, stress-testing it against alternatives of RE with storage. To limit the systemic costs that procurers may end up paying, the cost advantage ought to be done on the model of the payout and the financial mechanism of the power generator. This is to avoid the illusion of lower tariff yet higher overall payout.

- **Align flexible operation regulations with contractual/financial reforms:** Technical regulations related to flexible operations should be accompanied by corresponding commercial mechanisms. As flexibility requirements expand, regulatory frameworks should provide clarity regarding Change in Law treatment, cost recovery, and tariff adjustment to ensure that operational reforms are implemented without prolonged regulatory uncertainty. The CERC/ERCs ought to make a proactive change by making flexible operations the foundation and set strict exception parameters.

- **Improve operational transparency of units:** Operational parameters such as annual efficiency, emission intensity, flexible operation performance, low-load capability and maintenance records should become part of periodic reporting between contracting parties. Better information will enable improved asset management and support evidence-based procurement decisions. Data generated can be utilised to reform the Merit Order Dispatch in the long-run.

- **Differentiate availability factor for solar and non-solar hours:** The current practice of applying a uniform annual availability factor across all hours of the day should be reviewed to reflect the evolving operational role of coal-based TPPs. With flexible operations becoming the norm in an RE-rich power system, especially during daytime, the PPAs should recognise distinct availability requirements during solar and non-solar hours, aligning payments with actual system needs. The CERC/ERCs along with GRID-India can undertake a systemic review on need and capability basis and recommend alterations in the CEA's phasing plan on unit prioritisation.

- **Incentivise efficient, low-carbon thermal generation:** Regulatory frameworks and future PPAs should establish measurable efficiency and emission intensity benchmarks to reduce CO_2 emissions from thermal generation. Incentivise better-performing thermal generating units in the Merit Order Dispatch. Recognising operational efficiency through dispatch preference or performance-linked incentives will promote lower fuel consumption, reduced emissions and improved system-wide cost efficiency while supporting the nation's energy transition.

- **Align regulation and fuel-supply arrangements with PPA reform**: The CERC/SERCs should align FSA and their committed offtake quantities with the technical requirements for flexible operations, with clear provisions for Change in Law, cost recovery and tariff adjustment, reducing regulatory uncertainty around contractual reforms. Fuel supply and linkage arrangements should similarly provide for release or restructuring where the underlying PPA is renegotiated, restructured or exited, preventing fuel contracts from creating a second layer of long-term lock-in.

Annexure

Mathematical derivation of Debt and Equity payout over different tenures within Chapter 3 of the report.

Step 1: Debt Recovery

Opening Debt at COD: **₹11,552.45 crore**

Recovered over the selected PPA tenure using the standard annuity equation at **8%.**

$A_D = P_D$

Where:

- P_D = ₹11,552.45 crore
- i = 8%
- n = PPA tenure

Outputs:

- Annual Debt Payment
- Total Debt Payments
- Total Interest Paid

Step 2: Equity Recovery

Opening Equity at COD: **₹ 7,216.76 crore**

This is recovered separately assuming investors continue to receive a **15% annual return**

Exactly the same annuity equation has been used, except with the equity return.
Where:

- P_E = ₹ 7,216.76 crore
- R = 15 %

Outputs:

- Annual Equity Payment
- Total Equity Payout
- Additional Return earned over original equity investment

Step 3: Total Annual Capacity Payment

For every PPA tenure,

$$A_{Total} = A_D + A_E$$

And

Total Payout = Debt Payments + Equity Payments

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India's power sector is transitioning towards a renewable energy-driven future, fundamentally changing the operational role of coal-based thermal power plants. While coal is increasingly required to operate flexibly to complement renewable energy, the long-term Power Purchase Agreements (PPAs) governing these plants continue to reflect an era of baseload generation and power shortages. This growing disconnect has significant implications for consumer costs, operational efficiency and renewable energy integration.

Through legal, regulatory and financial analysis, RTI-based research, and domestic and international case studies, this report examines how existing thermal PPAs contribute to long-term contractual lock-ins and identifies opportunities for reform. It analyses the economics of current PPA structures, evaluates pathways for renegotiation, and proposes a modern Thermal PPA Framework with suggestive contractual clauses and policy recommendations. The report argues that contractual certainty and adaptability are complementary, and that modernising thermal PPAs is essential to reduce avoidable system costs while supporting India's evolving electricity system and decarbonisation pathway.

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