India Solar Curtailment & Evacuation Planning 2026: EPC, Grid and Revenue Risk

By Sudarshan Karweer · 25 August 2026 · growthifye.com

A 2026 India guide to solar evacuation, curtailment, substation planning, EPC design and revenue-risk mitigation for C&I and utility projects.

India's solar market in 2026 is no longer constrained only by module pricing, ALMM availability or CFA eligibility. For many projects, the harder commercial question is whether the plant can evacuate power reliably, avoid hidden curtailment losses and reach stable commissioning without substation, metering or transmission bottlenecks. This is true across utility-scale parks, state tenders, open-access C&I projects and emerging solar-plus-storage portfolios.

For developers, lenders and C&I offtakers, evacuation planning now sits at the centre of bankability. A project with a competitive EPC price but weak grid access can underperform a slightly more expensive project with stronger interconnection design, better load-flow analysis and realistic assumptions on line availability. In several states, developers are learning that the difference between a 19% CUF and a 21% CUF model is not only irradiation or DC/AC ratio. It is often evacuation architecture, substation readiness, feeder constraints, scheduling discipline and the commercial treatment of grid restrictions.

This article explains how solar evacuation and curtailment risk should be evaluated in India in 2026, what EPC and advisory teams must check before financial closure, and how project stakeholders can protect yield and revenue.

Why evacuation planning has become a first-order project risk in 2026

India added substantial solar capacity over the last few years, but transmission and distribution upgrades have not always moved at the same pace as generation additions. The result is a familiar problem: generation assets are ready, but bays, pooling substations, upstream transformers, protection approvals or line strengthening are delayed. Even where physical evacuation exists, operational restrictions may appear during low-demand periods, maintenance windows or local network congestion.

Three trends have made this more visible in 2026:

- Larger renewable penetration in high-resource states such as Rajasthan, Gujarat, Karnataka, Andhra Pradesh and Tamil Nadu
- Continued growth in interstate open access and captive/group captive C&I solar where injection and drawal patterns differ sharply by time block
- Rising deployment of hybrid and BESS-linked projects, which expose weaknesses in interconnection philosophy if not engineered correctly

In practical terms, evacuation risk affects five bankability outcomes:

- Delay in COD and revenue commencement
- Lower net generation due to curtailment or transformer clipping outside plant boundaries
- Additional capex for line extension, bay works, reactive compensation or protection modifications
- Scheduling and deviation penalties where injection cannot match committed profiles
- Stress on debt service coverage if P90 assumptions did not include realistic grid constraints

For utility developers, one to three months of COD delay can materially change project IRR if tariff is tight. For C&I projects, poor evacuation planning can erode the expected landed power benefit versus discom tariff, especially where savings assumptions are only INR 1.0 to 2.5 per kWh below grid power after wheeling, banking and losses.

Where curtailment risk actually comes from in Indian solar projects

Curtailment is often discussed as if it were one single event, but in India it usually appears through several layers of technical and commercial constraints. Advisers should separate them early.

First is pre-commissioning or structural evacuation delay. This happens when the project is physically complete but cannot inject because the evacuation line, bay, meter approval, SCADA integration or utility shutdown has not been completed. These delays are common around state substations, pooling stations and CTU/STU interfaces.

Second is network congestion during operation. A project may have full commissioning approval but still face backing down during periods of local oversupply, downstream line loading, transformer outage or system balancing constraints. Curtailment may be more severe in weak-grid areas or on feeders with rapid renewable additions.

Third is internal plant clipping that gets mistaken for external curtailment. Poor collector-system design, undersized evacuation transformers, thermal limitations in HT cables, or a conservative plant controller can all reduce export. Lenders increasingly ask for a clear separation between plant-side export constraints and utility-side curtailment.

Fourth is commercial curtailment hidden in scheduling practice. In open-access projects, if the plant is not forecasting accurately, the operator may intentionally back down to reduce deviation exposure in some time blocks. This is not the same as grid-enforced curtailment, but it still reduces realised revenue.

Typical curtailment or evacuation-related loss ranges in India vary widely by state and project type:

- Well-located utility-scale projects with strong transmission access: often below 1% to 2% annual loss
- Projects facing periodic bay or line constraints: around 2% to 5%
- Congestion-prone locations or weak distribution-connected C&I projects: 5%+ in stressed cases

These are not universal assumptions. Site-specific grid studies matter far more than generic benchmarks.

What EPC and advisory teams must check before land finalisation and bid submission

Many evacuation problems start before the EPC contractor is appointed, but EPC scope and design choices determine whether those problems become manageable or expensive. By 2026, a serious development process should include a full interconnection diligence package before bid finalisation or land locking.

Key questions include:

- What is the approved point of interconnection: 11 kV, 33 kV, 66 kV, 110 kV, 132 kV, 220 kV or above?
- Is the evacuation through discom, STU or CTU infrastructure?
- Is the project connecting to an existing bay, a new bay or a dedicated pooling substation?
- What is the actual spare transformation and line capacity, not only the theoretical sanctioned capacity?
- Are there known outages, congestion history or seasonal backing-down instructions on that node?

- What utility approvals are needed for protection settings, ABT meters, SCADA, remote terminal units and plant controller logic?

For utility-scale projects, developers should insist on updated single-line diagrams, substation loading snapshots and transmission readiness timelines. For C&I open-access projects, teams should examine feeder-level behaviour and not rely only on state-level policy summaries.

A robust grid diligence exercise typically includes:

- Load-flow study for maximum solar export and minimum local demand conditions
- Short-circuit study and breaker duty check
- Reactive power and voltage-control assessment
- Harmonic review for inverter-dense systems where applicable
- N-1 and contingency review for transformer or line outage scenarios
- Review of metering architecture and communication requirements

In many states, developers underestimate approval lead times. Protection coordination, relay settings, metering integration and utility witness tests can add weeks even after construction is complete. This timing should be reflected in EPC milestones and liquidated damages structure.

Design choices that reduce export loss and commissioning friction

Solar EPC strategy can materially reduce evacuation-related risk even when grid conditions are imperfect. The right design choices are not glamorous, but they protect generation and speed up utility acceptance.

One important decision is plant sizing against interconnection capacity. Aggressive DC oversizing may improve annual energy yield, but if the export node is regularly saturated or if utility restrictions are frequent in peak hours, the incremental DC capacity may deliver a weak return. In 2026, many ground-mount projects in India still target DC/AC ratios around 1.20 to 1.35 depending on irradiation, tariff and module cost. But where evacuation is uncertain, that ratio should be tested against real export constraints, not just module economics.

Transformer and cable sizing also need closer scrutiny. A project that saves capex through tighter thermal margins may experience higher losses, voltage instability or constrained export in high-irradiance conditions. For MW-scale C&I projects, the cost difference between a minimally compliant and a resilient evacuation design is often small relative to the long-term revenue impact.

The following EPC measures are especially valuable:

- Conservative transformer sizing with realistic ambient derating
- Collector-system design that limits voltage drop and hot spots
- Proper reactive compensation strategy aligned with utility requirements
- Plant controller integration for active/reactive power control and ramp-rate compliance
- Redundant communication paths for SCADA and meter data availability
- Early factory and site testing of protection, synchronization and telemetry

For projects using ALMM-listed modules and approved inverter supply chains, equipment availability in 2026 has improved compared with earlier tight cycles, but bay equipment, switchgear and utility-approved metering can still create bottlenecks. Long-lead items should be identified during procurement planning, especially for 66 kV and above interfaces.

Indicative evacuation-related capex ranges vary by voltage level, line length and right-of-way complexity. In practice:

- Short 11 kV or 33 kV C&I connections may add a modest amount per MW, but discom augmentation costs can change the economics sharply
- Dedicated 33 kV to 132 kV lines for utility or large open-access plants can significantly increase capex depending on route and terrain
- Pooling substation and bay costs can be material and should never be left as a vague provisional sum in financing models

A lender-grade budget should include contingency for route changes, tower/foundation variation, utility scope changes and shutdown coordination.

Revenue modelling: how lenders and offtakers should quantify curtailment risk

The most common mistake in project underwriting is treating curtailment as a generic 1% haircut without evidence. In 2026, that is rarely sufficient for investment committee comfort, especially for projects with tight tariffs or high leverage.

Revenue models should distinguish at least four categories:

- Grid unavailability before COD
- Forced export restriction after COD
- Internal plant-side evacuation losses
- Scheduling-related energy loss or penalties

For utility PPAs, teams should review the exact compensation language for deemed generation, backing down and must-run treatment. The practical value of must-run status depends on enforcement, system conditions and settlement mechanics, not just the phrase in policy discourse.

For C&I projects, the analysis should include:

- Hourly coincidence of solar generation with consumer load
- Banking rules where available
- Wheeling and transmission loss assumptions
- Cross-subsidy surcharge, additional surcharge and other open-access charges where applicable
- Curtailment sensitivity under low-load weekends and holidays

A sensible lender case often uses multiple scenarios rather than one headline assumption:

- Base case with observed node readiness and moderate operational restrictions
- Downside case with delayed bay readiness or seasonal congestion
- Severe case with higher curtailment plus slower scheduling stabilisation in the first year

For many C&I solar projects, a 3% to 4% reduction in net delivered energy can materially affect the savings narrative if the contracted tariff discount to discom supply is narrow. For utility projects discovered through competitive bidding, even a sub-2% persistent export loss can pressure DSCR if the tariff is already in the INR 2.3 to 3.2 per kWh range and financing is structured tightly. Project-specific tariffs vary by tender, state and offtake structure, but the message is simple: evacuation underperformance translates quickly into equity stress.

Policy and implementation issues to watch across Indian states

The policy environment in 2026 supports continued renewable growth, but implementation risk remains highly state-specific. Advisory teams should monitor not only MNRE notifications and central framework changes, but also STU/discom circulars, open-access procedures, state commission orders and local engineering practices.

Key watchpoints include:

- Changes in open-access processing timelines and technical approval conditions
- State-level banking restrictions or time-of-day treatment that affect solar export value
- Utility requirements for remote curtailment capability and telemetry integration
- Evolving standards for BESS-coupled interconnection where solar shares the node
- Clarifications on protection architecture, islanding logic and relay coordination

CFA-linked rooftop and distributed projects bring a separate layer of administrative discipline. Even where subsidy support improves customer economics, poor meter planning, vendor documentation gaps or delayed utility inspection can slow energisation. Growth in PM Surya Ghar-linked rooftop ecosystems has improved market awareness, but execution quality still differs significantly by installer and utility territory.

For large projects, the interaction between SECI-style procurement frameworks, state offtake realities and transmission availability remains a live issue. Developers should avoid assuming that a strong PPA alone solves evacuation risk.

A practical due-diligence checklist before financial closure

Before FC, disbursement or final EPC award, project stakeholders should ask for a concise but evidence-backed evacuation readiness pack. This should include:

- Sanction letter for interconnection capacity and voltage level
- Utility-approved SLD and interconnection concept
- Status of bay allocation, line route approval and land/right-of-way for evacuation assets
- Transformer, switchgear and protection specification with delivery timelines
- Metering and communication architecture, including utility integration requirements
- Grid study reports with assumptions clearly stated
- Construction timeline aligned with utility shutdown and witness-test windows
- Revenue sensitivity for 1%, 3% and 5% export restriction scenarios
- Clear allocation of responsibilities between developer, EPC contractor and utility-facing consultant

Where the node is congested or approvals are still fluid, the project should carry a higher contingency, stricter milestone monitoring and a more conservative COD plan. Developers sometimes resist this because it weakens headline returns. In reality, it improves credibility and protects financing.

The strongest solar projects in India in 2026 are not merely those with low module prices or fast installation schedules. They are the ones where land, interconnection, protection, metering, scheduling and utility coordination are integrated from day one. Evacuation planning is no longer a back-end engineering task. It is a core commercial discipline.

If you are evaluating a solar, open-access or solar-plus-storage project and need independent support on evacuation diligence, EPC risk, ALMM-linked procurement, commissioning readiness or financing assumptions, contact Growthifye’s advisory desk.

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Over 23 years in management consulting — concept to scale — building and scaling new-age digital and energy businesses. An EY alumnus, Sudarshan leads Growthifye's renewable energy & storage advisory, EPC, transmission engineering and green-financing practices for developers, utilities and C&I consumers across India.

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