Curtailment, Scheduling and DSM in Open Access Solar PPAs in India 2026

By Sudarshan Karweer · 25 August 2026 · growthifye.com

A 2026 India guide to curtailment, scheduling, DSM, banking and contract design in open access solar PPAs for C&I buyers.

India's open access market has matured beyond headline tariff comparisons. In 2026, the real commercial differentiator in many corporate PPAs is not only the discovered energy price, but how curtailment risk, scheduling accuracy, deviation settlement mechanism (DSM), banking treatment and settlement clauses are allocated between generator, trader and consumer. For commercial and industrial buyers, these details can move landed power cost by Rs 0.20-0.90/kWh, enough to erase an apparent saving versus DISCOM supply or materially improve it.

This article focuses on a narrower and under-discussed topic than generic open access pricing: how operational risk allocation works in open access solar and hybrid PPAs in India in 2026, and how that risk affects the final economics for C&I consumers, developers, lenders, utilities and policymakers.

Why operational risk now matters as much as tariff

For a typical HT industrial consumer evaluating open access solar in 2026, the visible quoted tariff may be around Rs 2.70-4.20/kWh depending on state, project configuration, tenure, delivery structure and whether the deal is group captive or third-party. But the final landed cost also depends on:

- interstate transmission system or state transmission system charges, where applicable
- wheeling charges and wheeling losses
- cross-subsidy surcharge and additional surcharge
- standby and balancing arrangements with the DISCOM
- banking charges, banking period and drawal restrictions
- forecasting and scheduling penalties or DSM exposure
- compensation framework for grid unavailability and backing down
- must-run treatment in practice, not only in policy text

In many states, buyers have already optimised the basic structural question of third-party versus group captive. The next frontier is operational discipline. A consumer with a nominal Rs 1.50/kWh saving versus grid tariff can lose 15-40 percent of that benefit if scheduling, curtailment compensation and banking rules are poorly understood.

Curtailment in 2026: policy promise versus practical reality

Renewable projects are generally granted must-run status under central policy principles, but curtailment disputes continue in several states. The issue for open access consumers is that there are at least three very different curtailment scenarios, and each has different commercial implications:

- transmission constraint curtailment at the state or interstate level
- distribution-level restriction, including local evacuation bottlenecks
- backing down linked to system balancing, frequency management or grid security claims

Developers often assume must-run protection will fully support revenue recovery. In practice, the PPA and OA approval ecosystem matters more. A buyer should ask four direct questions before execution:

- Is deemed generation or deemed energy compensation explicitly provided in the PPA?
- If curtailment happens, who bears unrecovered transmission, wheeling and OA charges?
- Is compensation based on fixed tariff, variable margin, or only debt-service support?
- Does the contract distinguish force majeure from grid unavailability caused by utility instructions?

A robust contract in 2026 typically provides for compensation where generation is available but evacuation is prevented by non-force-majeure grid restriction attributable to transmission or distribution system constraints. However, many market PPAs still use diluted language such as “parties to discuss in good faith,” which is commercially weak and lender-unfriendly.

For lenders, a solar OA asset with no clear curtailment payment mechanism can show DSCR compression in weak-grid periods. For consumers, the same event may trigger unexpected fallback procurement from the DISCOM at Rs 7-10/kWh effective industrial tariff, especially where the renewable source was expected to meet daytime process load.

Scheduling, forecasting and DSM: the hidden cost centre

The most overlooked line item in many boardroom models is forecasting and deviation risk. India’s renewable scheduling framework has evolved across central and state regulations, but from a commercial perspective the key issue is simple: who forecasts, who schedules, who pays for error, and how are penalties shared?

In 2026, most professionally managed OA portfolios use specialised forecasting engines, SLDC/RLDC compliant scheduling processes and active revision protocols. Yet variability remains material because:

- solar generation changes rapidly with cloud movement
- state-level implementation standards differ
- communication outages affect meter visibility and schedule revision ability
- hybrid and RTC-style products can reduce, but not eliminate, deviation risk

For a plain-vanilla open access solar project, forecasting error costs may be modest in a good month and spike in monsoon or shoulder seasons. On an annualised basis, a well-managed asset may contain such costs to around Rs 0.03-0.10/kWh. A weakly managed one can see Rs 0.15-0.30/kWh or more in combined imbalance, scheduling and related commercial losses, especially when backed by unfavourable contract pass-through provisions.

Buyers should review whether the seller tariff is:

- ex-busbar, with all OA and scheduling risk passed through
- delivered at consumer meter, with seller assuming more balancing responsibility
- shape-adjusted or time-block committed, especially in hybrid structures

This distinction matters. A cheaper ex-busbar tariff can end up costlier than a slightly higher delivered tariff once deviation, losses and replacement power are properly modelled.

A practical procurement model is to simulate 15-minute block consumption against expected renewable injection, then evaluate:

- residual grid draw and applicable demand charges

- impact of non-coincident solar generation profile
- monthly banking dependence
- DSM or scheduling under-generation exposure
- spill energy under no-bank or limited-bank conditions

For continuous-process plants, textiles, metals, chemicals, data centres and food processing facilities, this granularity is now essential. Annual average numbers are no longer enough.

Banking rules can make or break PPA value

Banking was once treated as a generic advantage of open access solar. In 2026, it is highly state-specific and often constrained by time-of-day drawal, monthly settlement, banking fees or outright disallowance for certain categories.

Key variables include:

- whether banking is allowed at all for open access consumers
- monthly versus annual banking
- banking charge in cash or energy terms
- permitted drawal windows, including peak-hour restrictions
- treatment of unutilised banked energy at month-end or year-end
- whether group captive and third-party consumers are treated differently

Where banking is liberal, solar can be integrated more efficiently against daytime and partial evening loads. Where banking is restrictive, a consumer may face spill energy in low-load months and expensive DISCOM drawal in non-solar periods. The combined effect can alter realised renewable utilisation by 5-20 percentage points depending on load shape.

Illustratively, consider a consumer signing an OA solar PPA at Rs 3.10/kWh in a state where banking is monthly with 8 percent energy deduction and no peak-hour withdrawal. If 18 percent of injected energy needs banking and 30 percent of that banked energy cannot be effectively withdrawn due to timing restrictions, the practical landed cost can rise by roughly Rs 0.12-0.25/kWh after accounting for losses, forfeiture and replacement power. In contrast, a project in a more flexible banking regime may preserve most of the nominal tariff advantage.

This is why policy comparisons should not stop at wheeling and surcharge tables. Banking architecture often decides whether an open access project is merely acceptable or highly competitive.

Contract design: third-party and group captive need different risk clauses

Even though the broad structural comparison between third-party and group captive has been widely discussed, their operational-risk contracting still deserves separate attention.

In third-party PPAs, buyers usually focus on tariff certainty and maximum pass-through caps. The seller or trader may take responsibility for scheduling, OA approvals and meter interface, but the contract should specify:

- exact change-in-law treatment for transmission, wheeling, CSS, AS and banking charges
- seller obligations for schedule submission and revision
- penalty sharing for forecasting errors and grid code non-compliance

- deemed delivery or compensation during curtailment not attributable to buyer default
- replacement power support, if any, during prolonged project outage

In group captive structures, consumers often assume greater control but also carry more governance and compliance risk. The legal requirements around minimum 26 percent equity by captive users and 51 percent annual consumption by captive users remain central. However, operationally, group captive contracts should also define:

- how DSM and scheduling costs are allocated among captive users
- what happens if one user under-consumes and the 51 percent rule is threatened
- treatment of banked energy where multiple users have different drawal patterns
- waterfall for common charges, including SLDC, meter, scheduling and legal compliance costs
- dilution, exit and substitution mechanics for captive shareholders

In 2026, more disputes are emerging not because captive users misunderstand headline savings, but because they did not anticipate uneven consumption patterns, variable plant generation and cost-sharing friction across members.

Landed cost modelling: a practical framework for CFOs and developers

A bankable open access assessment should use at least three scenarios: base case, stressed operations case and regulatory change case. A simple but effective landed cost model includes the following layers.

First, energy price and generation assumptions:

- contracted tariff or tariff formula
- CUF assumptions by month
- degradation and availability
- seller margin if through a trader or aggregator

Second, network and statutory charges:

- transmission charges and losses
- wheeling charges and losses
- cross-subsidy surcharge
- additional surcharge
- SLDC/RLDC and scheduling charges
- metering and application costs

Third, balancing and operational adjustments:

- banking charges and losses
- estimated curtailed units
- expected spill due to load mismatch
- DSM or forecasting-related costs
- replacement power cost for under-supply hours

Fourth, tax and accounting elements:

- GST treatment on service components where applicable

- treatment of energy charges versus facilitation charges
- internal hurdle rate and discounting assumptions

For many C&I buyers in 2026, a realistic saving band versus DISCOM power is not a single number but a range. For example:

- nominal headline saving: Rs 1.80/kWh
- after OA charges and losses: Rs 1.15/kWh
- after banking and spill adjustment: Rs 0.95/kWh
- after DSM and replacement power stress case: Rs 0.70/kWh

That may still be attractive over a 15-25 year tenor, particularly for consumers facing grid tariffs of Rs 8-11/kWh. But it is very different from a simplistic tariff comparison presented in early-stage sales decks.

What policymakers and utilities should watch

A mature open access ecosystem needs better alignment between RE procurement goals and operational settlement frameworks. Several reforms would materially reduce friction in 2026 and beyond:

- standardised treatment of renewable curtailment compensation across states
- clearer and more uniform banking rules with predictable settlement
- transparent publication of OA approval timelines and rejection reasons
- stronger digital infrastructure for metering, forecasting and schedule revision
- harmonised state-level DSM implementation for variable RE and hybrid plants

Utilities also benefit when OA consumers can forecast and settle more efficiently. Better scheduling discipline reduces system balancing stress and avoids adversarial disputes. Policymakers should recognise that uncertainty around curtailment and banking pushes up risk premium, which ultimately raises delivered renewable cost for industry.

For developers and lenders, the message is straightforward: the next phase of competitive differentiation is not only lower capex or lower nominal tariff. It is superior risk engineering, cleaner contracts, stronger scheduling operations and credible landed-cost transparency.

Open access solar and hybrid PPAs remain one of the strongest decarbonisation and power-cost management tools for Indian C&I consumers. But in 2026, the winners will be buyers and developers who underwrite the operating mechanics with the same rigour they apply to tariff negotiation.

If your organisation is evaluating open access procurement, restructuring a group captive arrangement, or stress-testing landed cost under state-specific charges, banking and DSM assumptions, contact Growthifye's advisory desk for transaction support, commercial modelling and implementation strategy.

ABOUT THE AUTHOR

Sudarshan Karweer — Chief Executive Officer, Growthifye

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.
Contact: info@growthifye.com · +91 84510 99371 · growthifye.com