India 2026 Hard-to-Abate Decarbonisation: Electrification vs Green Hydrogen

By Sudarshan Karweer · 05 September 2026 · growthifye.com

A 2026 India playbook for choosing electrification or green hydrogen for industrial decarbonisation, with costs, policy and MRV.

Indian industry has already captured many of the simpler decarbonisation levers: LED retrofits, VFDs, waste heat recovery, rooftop solar and basic process optimisation. In 2026, the harder question is what comes next for thermal loads, chemical feedstocks and high-temperature processes that still depend on coal, petcoke, furnace oil, diesel and natural gas. For sectors such as steel, chemicals, refineries, fertilisers, ceramics, glass, food processing and heavy engineering, the decision is increasingly framed as electrification versus green hydrogen.

That framing is useful, but incomplete. In practice, industrial decarbonisation in India is not a binary choice. The right pathway depends on temperature range, duty cycle, process chemistry, power quality, renewable-energy access, land and water constraints, offtake profile, financing structure and future carbon exposure under domestic and export regimes. In many cases, the least-cost pathway is direct electrification first, with hydrogen reserved for feedstock uses or process segments where molecules are genuinely required.

This article sets out a 2026 decision framework for Indian commercial and industrial players assessing hard-to-abate decarbonisation. It focuses on where electrification is commercially ready, where green hydrogen is strategically justified, how to compare levelised costs, and what lenders and boards should expect in terms of MRV, risk allocation and policy compliance.

Why this choice matters in India in 2026

The economics of industrial decarbonisation are tightening from three directions at once.

First, delivered renewable electricity in India remains globally competitive in several states. For large open-access consumers, plain vanilla solar-wind combinations can still translate into blended delivered power in the broad range of Rs 4.0-6.5/kWh depending on state charges, banking rules, profile shape, contract tenor and scheduling strategy. Where storage or firming is added for higher process reliability, the delivered cost rises, but remains commercially viable for many thermal replacements below 200°C and for selected motor-driven or electro-thermal applications.

Second, the carbon-management burden is rising. BRSR Core expectations, customer disclosures, export-buyer questionnaires, product carbon footprint requests and lender due diligence now require more defensible emissions baselines. Even where domestic carbon prices remain modest or phased, companies can no longer justify technology choices only on fuel savings; they must demonstrate auditable abatement.

Third, policy momentum is stronger around both industrial electrification and green hydrogen. The National Green Hydrogen Mission continues to shape project development, electrolyser manufacturing and pilot offtake. At the same time, state-level support for renewable open access, transmission planning and captive structures continues to improve, even if implementation quality still differs sharply by state.

For decision-makers, this means capex choices made in 2026 can lock in emissions and cost structures for 10 to 20 years. A new boiler, kiln, reformer, dryer or materials-handling system approved today will likely still be operating when carbon reporting, product-level emissions scrutiny and low-carbon procurement become far more stringent.

The first principle: electrify wherever electrons can replace heat efficiently

The strongest commercial error we still see in Indian industry is treating hydrogen as a broad substitute for all fossil fuels. That is rarely optimal. When a process can use electricity directly, direct electrification usually beats green hydrogen on energy efficiency, landed cost and operational simplicity.

A practical comparison makes this clear. If renewable electricity costs Rs 5/kWh, one MWh of electricity costs about Rs 5,000. Using that electricity directly in electric boilers, heat pumps, induction systems, resistance heating or electric arc equipment avoids conversion losses. If the same electricity is first converted into hydrogen through electrolysis, then compressed, stored, transported and reconverted to usable heat, the effective delivered energy cost rises materially.

In 2026 Indian conditions, green hydrogen production costs for well-structured projects are still commonly discussed in a wide band, often around Rs 260-400/kg depending on renewable sourcing, electrolyser utilisation, water treatment, financing, storage and distribution assumptions. Since 1 kg of hydrogen contains roughly 33.3 kWh lower heating value, the fuel-equivalent energy cost alone often lands near Rs 7.8-12/kWh before accounting for burner retrofits, compression, storage and end-use efficiency effects. In many direct-heat applications, that remains significantly above direct electrification.

That is why the no-regret order of action for most C&I users remains:

- reduce process energy intensity
- recover waste heat
- switch low- and medium-temperature thermal loads to electricity where feasible
- decarbonise purchased electricity through renewable procurement
- reserve green hydrogen for feedstock or hard-to-electrify high-temperature applications

Typical applications where electrification is often ready or approaching readiness include:

- boilers and hot-water systems below roughly 150-180°C using electrode or resistance boilers
- drying, washing, blanching and sterilisation in food and pharma
- low- to medium-temperature process heating using heat pumps, electric thermal oil systems or infrared systems
- induction melting and heating in metals fabrication
- electric forklifts, yard mobility and selected material handling
- mechanical drive replacement where steam turbines can be retired in favour of efficient electric motors

For these categories, companies should examine not only fuel substitution but full-system redesign. Many plants still use steam where hot water, thermal fluids, direct electric heating or heat pumps can cut losses. In such cases, the economics improve because electricity is replacing both fuel and steam-distribution inefficiency.

Where green hydrogen does make strategic sense

Hydrogen is not a universal fuel, but it is important where direct electrification is technically constrained or where hydrogen is itself part of the chemistry.

In India, the strongest strategic cases in 2026 are concentrated in five buckets.

- feedstock substitution in refineries, ammonia and chemicals, where grey hydrogen can be displaced over time
- iron and steel pathways, especially where DRI or future low-carbon ironmaking options are under evaluation
- very high-temperature process heat, generally above 500-800°C, where electric retrofits are difficult, though this remains process-specific
- backup reductant or fuel for niche hard-to-abate operations with limited electric alternatives
- export-oriented production where low-carbon molecule claims may support customer access or premium positioning, subject to robust MRV

Even in these sectors, the right answer is often not 100% hydrogen. Hybridisation is common. A plant may electrify auxiliary loads, compressed air, low-temperature heating and mobility while reserving hydrogen for reformer replacement, reducing atmospheres, feedstock or selected burners. This is why board-approved decarbonisation plans need a granular unit-operation view rather than a single plant-wide headline target.

Hydrogen also brings infrastructure realities that are often underappreciated in early-stage strategy decks.

- storage footprint and safety systems add cost and complexity
- dedicated pipelines are limited; trucked hydrogen raises delivered cost
- water quality and availability can become real constraints in water-stressed industrial belts
- electrolyser economics depend heavily on utilisation and power sourcing strategy
- intermittent renewable power can reduce electrolyser load factor unless grid balancing or storage is built in

For many industrial campuses, the commercially bankable model in 2026 is not merchant hydrogen purchase at scale but a phased on-site or near-site production strategy tied to a specific captive demand pocket and backed by long-term renewable supply.

A decision framework boards can actually use

Companies comparing electrification and hydrogen should move beyond generic net-zero narratives and apply a structured techno-commercial screen. A practical board paper should answer at least the following questions.

- What is the current baseline fuel mix by process line, temperature band and annual operating hours?
- Which loads are below 200°C, between 200-500°C and above 500°C?
- Is the energy demand for heat, reducing atmosphere or chemical feedstock?
- What is the current landed cost of coal, petcoke, FO, HSD, PNG or LPG after logistics and taxes?
- What renewable electricity structures are actually executable in the plant state: captive, group captive, third-party open access, utility green tariff or behind-the-meter?
- What are the network constraints, standby charges, banking rules and curtailment risks?
- What carbon exposure exists through customers, exports, financing covenants or future domestic compliance?
- What is the abatement cost in Rs per tCO_2e for each pathway, not just the energy savings?

This is where a MACC is useful, but only if done with operating realism. A marginal abatement cost curve for Indian industry in 2026 should include:

- capex by unit operation
- replacement cycle timing
- fuel and power escalation assumptions
- auxiliary power consumption
- downtime and retrofit complexity
- carbon-accounting boundary impacts across Scope 1 and Scope 2
- water, land and permitting requirements
- policy incentives and tax effects

In many studies, direct electrification options show lower abatement costs than hydrogen in the near term, sometimes even negative abatement cost when replacing expensive liquid fuels. Hydrogen options may remain positive-cost for several years unless linked to strategic customer requirements, internal carbon values or mission-driven funding support.

This is why many firms are now sequencing projects through [Net-zero roadmaps & MACC](/coreservices/netzerodecarbonisation/netzeroroadmapsandmacc) rather than approving a large hydrogen programme upfront.

India 2026 economics: how to compare pathway costs credibly

There is no single national benchmark because plant economics differ by state and process. But a few 2026 rules of thumb are useful.

For electrification:

- delivered renewable-backed power for large C&I users often ranges around Rs 4.0-6.5/kWh depending on state and structure
- RTC or firmer renewable supply with storage or balancing can move this higher, often into the Rs 6.5-8.5/kWh range depending on profile and contract design
- electric boilers can be economically attractive against LPG, diesel and furnace oil in several cases, but often struggle against very cheap domestic coal unless carbon, maintenance and emissions controls are included
- industrial heat pumps can deliver 2 to 4 times the useful heat per unit of electricity in suitable applications, dramatically improving economics versus resistance heating

For hydrogen:

- green hydrogen costs remain highly site-specific, often around Rs 260-400/kg in realistic 2026 project discussions
- delivered cost rises further with storage, compression, transport and low utilisation
- hydrogen is generally more viable where grey hydrogen displacement already exists, because handling systems, process familiarity and value recognition are better established

For carbon accounting:

- electrification usually shifts emissions from Scope 1 to Scope 2 unless paired with credible renewable procurement
- hydrogen from electrolysis is only as low-carbon as its electricity source and accounting method

- hourly or near-granular power matching is not yet universal in India, but scrutiny on temporal matching and market-based claims is increasing

A credible comparison therefore needs both energy LCOE and emissions intensity per unit of useful output. If two options produce the same heat duty but one creates operational flexibility, lower local pollutants and easier future compliance, that strategic value should be explicitly priced into the investment case.

Policy, MRV and bankability considerations

Technology choice is only half the story. In 2026, projects increasingly succeed or fail on documentation quality, compliance readiness and lender confidence.

For electrification projects, key diligence themes include:

- open-access contract enforceability and change-in-law treatment
- state-level wheeling, cross-subsidy surcharge and banking risk
- interconnection and power-quality impacts on sensitive processes
- metering architecture for attributable emissions reduction claims

For hydrogen projects, diligence expands to include:

- renewable additionality and power-sourcing traceability
- electrolyser performance guarantees
- water sourcing and effluent management
- storage and safety codes
- offtake certainty and take-or-pay structure
- MRV protocol for emissions intensity of produced hydrogen

This is where [Carbon accounting & disclosure](/coreservices/netzerodecarbonisation/carbonaccountinganddisclosure) and [Carbon markets & MRV](/coreservices/netzerodecarbonisation/carbonmarketsandmrv) become operational, not just reporting exercises. If a company cannot establish baseline fuel consumption, operating boundary, electricity source traceability and production-normalised emissions, it will struggle to defend claims to buyers, auditors, lenders or regulators.

Indian firms should also stay alert to evolving interactions between domestic carbon-market architecture, voluntary claims and export expectations. A poorly designed project that overstates abatement or mixes accounting boundaries can create future compliance risk. Conversely, a well-designed project with clear metering, data governance and auditable methodology can support stronger commercial outcomes, including customer retention and financing confidence.

A practical 24-month roadmap for Indian industrials

For most plants, the right 2026-2028 strategy is phased rather than ideological.

Phase 1: establish the baseline

- map fuel use by process, temperature and shift pattern
- create a line-level emissions inventory for Scope 1 and Scope 2
- identify hydrogen feedstock uses separately from thermal uses
- quantify current energy cost per tonne of product

Phase 2: execute no-regret electrification

- target low- and medium-temperature loads first
- retire expensive diesel, LPG and furnace-oil applications where feasible
- integrate renewable procurement into the business case rather than treating it as a separate workstream
- redesign utility systems, not just equipment replacements

Phase 3: screen hydrogen use cases narrowly

- prioritise existing grey hydrogen replacement, chemical feedstock or genuinely hard-to-electrify process steps
- run pilots with defined operating envelopes and safety protocols
- evaluate on-site production only where demand density and renewable access justify it

Phase 4: build the finance and MRV stack

- align project assumptions with board-level hurdle rates and lender requirements
- set up metering, data acquisition and monthly variance analysis
- convert engineering options into a MACC and capital-allocation plan
- prepare for assurance under BRSR Core, customer questionnaires and future market mechanisms

The central message is simple: electrification should be the default for many industrial decarbonisation opportunities in India, while green hydrogen should be deployed where process chemistry or very high-temperature constraints make molecules necessary. Companies that reverse this order risk overpaying for abatement and delaying execution.

For Indian C&I energy consumers, RE developers and financiers, 2026 is the year to move from broad net-zero ambition to process-level technology selection backed by hard numbers, policy realism and auditable MRV. The winners will be firms that choose the right decarbonisation vector for each unit operation, not those that chase the most visible headline technology.

If your organisation is evaluating process electrification, hydrogen pilots or plant-level decarbonisation sequencing, contact Growthifye’s advisory desk for a practical assessment of technology choice, economics, MRV and implementation strategy.

Explore Growthifye's related capabilities

This analysis connects directly to our advisory practice: [Carbon accounting & disclosure](/coreservices/netzerodecarbonisation/carbonaccountinganddisclosure) · [Net-zero roadmaps & MACC](/coreservices/netzerodecarbonisation/netzeroroadmapsandmacc) · [RE-led decarbonisation](/coreservices/netzerodecarbonisation/releddecarbonisation) · [Industrial efficiency & electrification](/coreservices/netzerodecarbonisation/industrialefficiencyandelectrification).

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