MINI-GRID MARKETS, MECHANISMS AND MONETISATION

DESIGNING FEED-IN FRAMEWORKS FOR INDIA

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1. INTRODUCTION AND CONCEPTUAL FRAMEWORK

1.1 The rural electrification challenge and mini-grid solutions

1.1.1 Global energy access gap and the role of decentralized systems

The challenge of ensuring reliable and affordable electricity access remains one of the most critical development imperatives of the twenty-first century. According to Tracking SDG 7: The Energy Progress Report by World Bank an estimated 666 million people globally still lacked access to electricity in 2024, underscoring persistent structural gaps in power systems[1]. While grid extension programmes in the country have expanded rapidly over the past two decades, electrification progress has not kept pace with population growth in many rural and remote regions. This has resulted in 'last-mile crisis' in energy access.

Beyond access, the quality and reliability of electricity supply remain significant and has under-examined challenges, even in countries that have achieved near-universal connections. Power systems continue to experience national-level supply deficits, transmission congestion, and distribution-level outages, resulting in intermittent and uneven service delivery. Reliability indicators such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) released of utilities/Discoms show substantial inter-state variation, with states such as Bihar, Jharkhand, and Uttar Pradesh consistently recording higher outage durations and interruption frequencies.[2]

However, these reliability metrics are mandated under Central Electricity Authority (CEA) regulations primarily for towns with populations exceeding 100,000, leading to a systematic data blind spot for rural settlements, cluster, and hamlets. Consequently, there is no comprehensive, granular evidence on reliability outcomes in sparsely populated rural areas, where grid infrastructure is weakest and service quality is likely to be poorest.

Traditional approaches to rural electrification, centred on extending national transmission and distribution networks, have proven economically challenging and logistically complex in areas characterized by low population density, difficult terrain, and limited economic activity. The capital expenditure required to connect remote settlements frequently reaches prohibitive levels in such challenging geographies, making these investments financially unsustainable without substantial public subsidies.

Against this backdrop, mini-grids have emerged as a critical intermediate solution for rural electrification. Defined as localized electricity generation and distribution systems typically ranging from 10 kW to few MW in capacity, mini-grids can operate independently or with the potential for future grid interconnection. These systems serve anywhere from a few dozen to several thousand customers in remote settlements, small towns, or agricultural communities where grid extension remains economically or technically infeasible in the near to medium term.

The technical and economic rationale for mini-grids is compelling. World Bank's Energy Sector Management Assistance Program (ESMAP) studies suggest that up to 490 million people—approximately half a billion—could be most cost-effectively served by mini-grids by 2030 under universal access scenarios[3]. This represents not only a stopgap measure but an optimal electrification pathway for specific demographic and geographic contexts. Mini-grids offer distinct advantages including rapid deployment (typically 6–9 months versus 5–8 years for grid extension), modular scalability aligned with demand growth, and the ability to leverage local renewable energy resources.

1.1.2 Evolution of mini-grids: From diesel-dependent to third-generation renewable systems

The evolution of mini-grid technology and business models can be broadly categorized into three distinct generations, each reflecting technological advancement and shifting policy priorities.

First-generation mini-grids (pre-1980s) were predominantly isolated diesel generator systems serving mining operations, plantations, or remote industrial facilities. These systems were characterized by high operational costs, significant greenhouse gas emissions, and dependence on unreliable fuel supply chains.

Second-generation mini-grids (1980s–2000s) saw the emergence of community-owned and operated systems, primarily utilizing small-scale hydropower and diesel-hybrid configurations. This era was marked by CSR/donor-funded projects emphasizing community participation and capacity building. However, these initiatives frequently struggled with financial sustainability, inadequate technical maintenance, and governance challenges.

Third-generation mini-grids (2010s-present) represent a fundamental transformation driven by several convergent technological and market developments. According to a study by the India Energy & Climate Center (IECC) at the University of California, Berkeley, module prices have declined sharply from about USD 2.4 per watt in 2010 to below USD 0.10 per watt (around Rs 9 per watt)—a reduction of nearly 95 per cent — have made solar-based generation economically competitive with diesel in most contexts[4]. Battery storage advancements, with lithium-ion costs falling by over 85 per cent to less than USD 120 per kWh (around Rs. 11,000 per kWh), enable reliable 24-hour power delivery. Smart and prepaid metering integrated with mobile payment platforms has revolutionized revenue collection, achieving rates exceeding 95 per cent compared to historical collection rates often below 60 per cent. Modern mini-grids are also engineered from inception for eventual interconnection with expanding national grids, incorporating appropriate voltage levels, synchronization capabilities, and bidirectional power flow management.

However, a critical economic challenge persists: while solar mini-grid generation costs have declined significantly, they still cannot compete with heavily subsidized single phase rural domestic tariffs that characterize most developing country power sectors. In India, rural residential tariffs range from Rs 3 to Rs 6.5 per kWh.

Yet solar mini-grids have achieved crucial competitive milestones which is around Rs 15 per kWh. They can provide electricity at a lower cost than diesel-based generation, which runs between Rs 25 to Rs 40 per kWh. Mini-grids also match the commercial rural 3-phase tariffs of Rs 9 to Rs 12 per kWh, making them economically attractive for agricultural processing units, telecom towers, rural enterprises, cold storage facilities, and small manufacturing units. This economic positioning creates a fundamental policy tension: mini-grids are commercially viable for specific customer segments but require tariff flexibility or subsidy mechanisms to serve residential loads at politically acceptable price points.

1.1.3 The grid arrival paradox: Learning from India's failed mini-grids

Despite their technical and economic advantages, mini-grids face a fundamental existential challenge that undermines private investment and threatens sector sustainability: the risk of national grid arrival. India's experience provides sobering evidence of how grid encroachment without adequate regulatory protection has systematically destroyed mini-grid investments across multiple states. Systems that once served as critical lifelines for rural communities for nearly a decade have been rendered financially unviable as the central grid arrived without structured integration or compensation frameworks.

Table 1: Defunct mini-grids in India due to grid arrival

Project name/ location	Capacity	Commis-sioned	Grid arrival	Failure year	Key details
Indrapur Island - G-Plot, Sundarbans, West Bengal	Solar AC microgrid 110 kWp	2004	2018	2018–19	Initially designed for 5 hours of evening supply, the system faced reduced capacity and functionality issues following Cyclone Aila in 2009, with supply dropping to 3 hours. While it provided electricity before grid-connected power arrived around 2018.
Rajat Jubilee Gosaba Block Sundarbans, West Bengal	Solar AC microgrid 84 kWp	2011	2018	2020–2022	Commissioned on 9 March, by WWF-India and CAT Projects Australia, it utilized the 'Bushlight India Model'. It is owned and managed by a local consumer cooperative society. As of 2022, some reports suggested that while parts of the microgrid might have faced reduced usage or become defunct after the arrival of grid-connected power in the region, the system was originally designed for a 15-year life span.
Annpur-Jamespur Gosaba Block Sundarbans, West Bengal	Solar AC microgrid 15.5 kWp	2017	2020	2020	The arrival of conventional grid-connected electricity to the island shortly after the project's start led to a decline in subscriptions. In Annpur-Jamespur, the batteries for street lamps were removed by the installing agency. Residents reported that the land, which could have been used for agriculture or beekeeping, was wasted on these inactive installations.
Patharpara Gosaba Block Sundarbans, West Bengal	Solar AC microgrid	2017	2020	2020–22	The solar mini-grid failed primarily due to unregulated grid arrival, which led consumers to abandon the system and stop payments. Weak community ownership, poor billing and collection, and land disputes.
Ravan Village Jashpur, Chhattisgarh	Solar AC microgrid 20kWp	2010	2018–2020	2020	The mini-grid collapsed due to multiple factors. Solar panel theft and inadequate community management undermined system viability when operations transferred to untrained villagers. Grid expansion during 2018–2020 proved decisive—despite frequent outages, consumers overwhelmingly preferred grid's 24/7 availability over mini-grid's limited 4–6-hour supply. CREDA ultimately dismantled the system in 2020, strategically repurposing components to augment capacity in high-demand villages.
Dharnai Jehanabad, Bihar	Solar AC microgrid 100 kWp	2014	2016	2018	The project illustrates inevitable failure without long-term regulatory and financial safeguards. Commissioned in 2014 as state's 'first solar village' project, it initially transformed electricity access after decades of deprivation. However, within three years the system deteriorated due to battery exhaustion and lack of maintenance. As subsidized grid power arrived at a lower tariff (Rs 3/kWh versus Rs 9/kWh for solar), users abandoned the mini-grid, leading to declining connections and project collapse.
Barapitha Khorda, Odisha	1 kWp	2015	2018	2018	The system was severely damaged during Cyclone Fani in 2017 and was never repaired due to limited technical capacity and unclear responsibility for upkeep. As grid electricity later reached the village, households shifted to the central grid, abandoning the solar system.
Darewadi Khed Taluka, Pune	9.36 kWp	2012	2021	2022	Although the system operated from 2012 and batteries were replaced in 2019, the central grid reached the village in 2021 without provisions for grid-connected operation or feed-in tariffs. As a result, the mini-grid could not transition to grid-interactive mode and lost its economic relevance.

India lacks a comprehensive public registry tracking defunct mini-grids, but documented cases reveal a catastrophic pattern. The failure timeline is remarkably consistent: systems operate functionally for 5–7 years during battery warranty periods, then face component failure requiring replacement costs precisely when subsidized grid electricity arrives, causing 80–90 per cent customer attrition and complete revenue collapse.

The arrival of subsidized grid electricity has systematically dismantled India's mini-grid infrastructure, rendering hundreds of systems obsolete regardless of their operational success. This displacement follows a brutal economic logic: grid tariffs of Rs 5-7/kWh, heavily subsidized by state utilities, make cost-reflective mini-grid rates of Rs 10-20/kWh commercially unviable overnight. When grid lines reach a village, 80-90 per cent of mini-grid customers defect immediately, collapsing revenue streams and forcing abandonment.

West Bengal's Sundarbans illustrates this trajectory. WBREDA's 17 solar microgrids functioned adequately until grid extension arrived between 2015–20. The Indrapur Island system served 120 households until grid arrival in 2018 prompted complete customer migration, leaving the mini-grid defunct. Chhattisgarh's CREDA adopted a pragmatic response to this inevitability: systematically dismantling 20–30 mini-grids post-grid arrival, salvaging components for redeployment rather than allowing complete waste.

The fundamental problem isn't technical failure—it's policy vacuum. India provides no feed-in tariff mechanisms enabling mini-grids to sell surplus power to distribution companies, no asset buyout formulas compensating stranded investments, and no hybrid operation frameworks allowing coexistence. Grid expansion programs like Saubhagya (2018) and RDSS (2022) accelerated this displacement, stranding crores of rupees across 100–200 defunct systems nationwide. Without regulatory intervention establishing compensation mechanisms or mandatory grid-integration pathways, every operational mini-grid faces the same fate upon grid arrival—regardless of service quality, community satisfaction, or technical performance.

1.1.4 From stranded assets to grid infrastructure: The case for integration

The arrival of the national grid in rural areas is often seen as the natural endpoint of mini-grid systems. In practice, however, grid extension does not erase the value created by decentralized electrification. One of the most important but underappreciated aspects of this value lies in last-mile distribution infrastructure—

the low-tension (LT, 440-volt three-phase) lines and connections that link medium-voltage feeders to homes, farms, and enterprises. In sparsely populated rural regions, this segment can account for roughly 40 percent of the cost of extending the grid, while also posing ongoing maintenance and billing challenges for distribution companies (DISCOMs).

Mini-grid operators, by necessity, build exactly this infrastructure. Their systems include village-level LT lines, service connections, meters, and local technical capacity for operation and repair. When the national grid eventually reaches these settlements, this infrastructure remains fully functional and represents significant sunk investment. Yet standard practice has often involved building parallel distribution networks or dismantling the mini-grid system altogether, resulting in duplication of assets and loss of locally developed capability.

A more efficient approach is possible through a hub-and-spoke or franchise model. Under this arrangement, the DISCOM supplies bulk electricity at wholesale tariffs to the existing mini-grid operator, who continues to manage local distribution, metering, billing, and collection. The operator shifts from generating and distributing power to providing distribution services alone, earning a margin on retail supply. For the DISCOM, this avoids capital expenditure on new last-mile lines and leverages a functioning local delivery system with established customer relationships.

Evidence from operating mini-grids shows why this can be attractive. Systems serving compact clusters of 50–500 consumers frequently achieve collection efficiencies above 90–95 per cent, often through prepaid or smart-metering models. Conventional rural feeders, by contrast, typically recover only about 60–70 per cent of billed revenue. Decentralized distribution nodes also reduce line length and technical losses, particularly in remote or difficult terrain. Integrating existing mini-grid networks can therefore improve reliability and financial performance relative to extending long radial feeders into dispersed settlements.

Several countries have explicitly enabled such integration. In Nigeria and Tanzania, regulations allow mini-grid operators to purchase electricity from the main grid while retaining local distribution franchises under hybrid or small power distributor frameworks. India currently has no equivalent provision. As a result, many functioning village distribution systems have been abandoned or dismantled once grid supply arrived, discarding both physical assets and accumulated local expertise. Energy storage adds another dimension to this integration opportunity. Mini-grid batteries—typically ranging from about 100 kWh to a few megawatt-hours—are increasingly consistent with India's evolving view of storage as active grid infrastructure rather than backup. Recent policy directions encourage pairing storage with distributed solar to improve reliability and manage midday surplus generation, while regulatory frameworks now recognize storage as a network asset capable of supporting system balancing and congestion management.

These developments align closely with the characteristics of mini-grid storage. Located near loads and renewable generation, such batteries can provide multiple distribution-level services. They can charge during periods of surplus or low demand and discharge during evening peaks, reducing stress on upstream networks. Their fast response supports voltage and frequency stability. They can absorb excess daytime solar output and release it later, smoothing variability and mitigating the 'duck curve.' During outages, they enable islanded operation, improving supply resilience in remote areas.

Utilities in several Indian states have already tendered large volumes of battery capacity for peak shifting and grid balancing. Yet mini-grid storage assets positioned at the distribution edge remain largely outside these procurement or service frameworks. The paradox is that utilities are procuring new storage for grid support while existing decentralized storage with similar capabilities risks becoming stranded when grid supply arrives.

The implication is that grid arrival need not mark the end of mini-grids. Instead, it can enable their evolution into distributed grid-support nodes. Local consumers would continue to be served through established village networks, while embedded storage participates in broader system services, compensated through capacity payments or service contracts. Such integration would convert potentially redundant assets into productive components of a more flexible and resilient distribution system.

Realizing this outcome requires regulatory recognition of mini-grids as distribution and storage service providers. Tariff and compensation mechanisms adapted to small-scale contexts are needed to value both local distribution franchises and distributed storage services. Without such frameworks, grid expansion will continue to displace viable decentralized infrastructure and erode rural technical capacity. The challenge, therefore, is not technical but institutional: aligning regulation so that grid extension builds upon, rather than replaces, the assets and capabilities already created by mini-grids.

1.2 Feed-in tariffs: Principles and adaptation for off-grid contexts

1.2.1 Traditional FiT mechanisms and their core design elements

Feed-in tariffs emerged as the dominant renewable energy policy mechanism in the 1990s and 2000s, pioneered most successfully in Germany, Spain, and Denmark. The traditional FiT model rests on three foundational pillars that collectively address fundamental market failures in renewable energy investment.

i) **Guaranteed grid access** provides renewable generators with non-discriminatory connection rights to transmission or distribution networks, removing critical barriers facing independent producers in utility-dominated markets.

ii) **Long-term purchase agreements** spanning 15-25 years deliver revenue certainty essential for project financing, with fixed-price or premium contracts specifying tariff levels and purchase terms.

iii) **Cost-based payment levels** cover technology-specific generation costs plus reasonable returns, typically 7–12 per cent IRR in European contexts, with tariffs differentiated by technology, project size, and resource quality reflecting underlying cost variations.

These mechanisms address the fundamental mismatch between long-term societal benefits of clean energy—reduced emissions, energy security, local economic development—and short-term economic calculations of private investors facing uncertain revenue streams and evolving technology costs. Germany's success exemplifies this approach: the Renewable Energy Act drove solar PV capacity from under 100 MW in 2000 to over 50 GW by 2020.

1.2.2 The off-FiT model: Bridging policy gaps for isolated systems

The recognition that traditional FiTs require fundamental adaptation for mini-grid contexts has led to the development of 'off-grid feed-in tariffs'. These adapted mechanisms attempt to preserve the core investment-enabling features of traditional FiTs while addressing mini-grid-specific challenges.

Key design innovations in off-FiT frameworks include:

1. **Hybrid tariff structures**: Rather than a simple per-kWh payment, off-FiTs often combine capacity-based payments (Rs/kW-month) with energy payments (Rs/kWh), ensuring revenue stability independent of consumption variability.
2. **Technology and size differentiation**: Recognizing that costs vary dramatically

across solar, hydro, biomass, and hybrid systems—and across project scales—off-FiTs typically establish technology-specific and capacity-band-specific tariff schedules.
3. **Subsidy integration**: Off-FiTs explicitly incorporate upfront capital subsidies, results-based financing (payments per connection), or operational support mechanisms to bridge the gap between cost-reflective generation tariffs and affordable consumer retail tariffs.
4. **Grid arrival protocols**: Leading off-FiT frameworks include clear provisions for what happens when the main grid reaches the mini-grid service area, including asset valuation methodologies, purchase obligations, or transition to hybrid operation models.
5. **Retail tariff flexibility**: Rather than mandating uniform national tariffs, off-FiTs often permit mini-grids to set retail tariffs within regulated ranges, allowing for cross-subsidization between customer classes and alignment with local ability to pay.

Tanzania's small power producer framework represents the most mature off-FiT model globally, incorporating standardized power purchase agreements with TANESCO (the national utility) for mini-grids that reach sufficient scale to export power, technology-specific tariffs, and complementary grant programs for connection subsidies and technical assistance.

However, even well-designed off-FiTs face implementation challenges stemming from limited regulatory capacity, utility reluctance to enter long-term purchase obligations, and political resistance to tariff differentiation that enables mini-grids to charge more than subsidized grid rates.

1.3 Research objectives and methodology

This research examines the design, implementation, and effectiveness of feed-in tariff mechanisms adapted for mini-grid contexts across diverse regulatory and market environments. The study is motivated by the critical policy gap between the demonstrated technical viability of renewable mini-grids and their persistent struggle to achieve commercial sustainability and scale.

Primary research objectives are threefold:
1. **To analyze tariff design methodologies and their alignment with mini-grid economic realities**, examining how different approaches to tariff calculation, technology differentiation, and subsidy integration affect project viability and investor confidence.

2. **To evaluate country-level implementation experiences**, identifying success factors, common pitfalls, and transferable lessons from jurisdictions with established off-FiT frameworks (Tanzania, Nigeria, Kenya and Indonesia) and those still developing appropriate policies.
3. **To develop evidence-based policy recommendations** for governments, regulators, and development partners seeking to establish or refine mini-grid FiT frameworks that balance investor returns, consumer affordability, fiscal sustainability, and strategic grid integration objectives—particularly recognizing the emerging value of mini-grid storage infrastructure for grid stability services.

Methodological approach: This study employs comparative policy analysis drawing on regulatory documents, project case studies, and technical-economic modelling. The research synthesizes international best practices while recognizing that effective policy design must account for country-specific contexts including existing tariff structures, regulatory capacity, fiscal constraints, and grid expansion planning.

The subsequent chapters examine these issues in depth, moving from tariff design methodologies (Chapter 2) through comparative country analysis (Chapter 3) to forward-looking policy recommendations and innovation opportunities (Chapter 4).

2. Tariff design methodologies and financial viability

2.1 Tariff calculation approaches for mini-grids

The determination of appropriate tariff levels for mini-grids represents one of the most technically complex and politically sensitive aspects of off-grid electrification policy. Unlike utility-scale generation where costs can be socialized across millions of customers, mini-grids must recover all system costs—generation, storage, distribution, metering, and operations—from a small customer base with limited ability to pay. This fundamental economic reality necessitates sophisticated tariff calculation methodologies that balance financial viability against affordability

Understanding mini-grid LCOE from capacity factors

Mini-grid capital costs are structured differently from utility-scale projects. Generation assets — solar panels, inverters, and mounting structures — account for only 35 per cent of total expenditure, compared to 70–80 per cent in utility-scale installations. Storage systems take up around 20 per cent, reflecting the need for battery banks to provide round-the-clock supply from an intermittent source. Distribution infrastructure — poles, cables, meters, and connection materials — accounts for 30 per cent, a cost category that simply does not exist in grid-connected generation. The remaining 15–20 per cent covers construction and other items.

Most mini-grids serve households whose peak demand falls in the evening. This means capacity factors are typically around 15 per cent, against roughly 90 per cent for utility-scale solar. Fewer units of electricity are generated from the same installed capacity, so capital costs must be recovered over a smaller output — directly raising the cost per unit:

Capacity factor impact example:

- 25 kW system with 60 per cent capacity factor: 25 kW × 1350 kWh × 0.60 = 20,250 kWh/year
- Same system with 30 per cent capacity factor: 50 kW × 1350 kWh × 0.30 = 10,125 kWh/year
  With identical costs, the levelized cost of electricity (LCOE) doubles when capacity factor is halved

Early-year cash flow is also under pressure. Mini-grids are typically oversized to accommodate future load growth, meaning capacity utilisation in the first few years may sit at just 20–30 per cent. LCOE models should reflect realistic annual demand growth of 10–20 per cent rather than assuming immediate full utilisation.

Battery replacement is a commonly missed cost. Storage capacity degrades at roughly 2–3 per cent per year, requiring replacement around years 7–10. Accounting for this properly raises LCOE by 12–18 per cent against models that assume batteries last the full project life.

Finally, distribution losses and collection efficiency matter. Technical losses are higher in rural mini-grids due to long low-voltage runs, and even prepaid metering systems typically achieve only 90–95 per cent revenue collection—not the 100 per cent that theoretical models assume.

imperatives while recognizing that the regulatory frameworks governing these calculations will ultimately determine whether mini-grids attract commercial investment or remain perpetually dependent on donor funding.

2.1.1 Levelized cost of electricity (LCOE) approach

The levelized cost of electricity remains the foundational metric for assessing mini-grid generation economics. LCOE represents the minimum average tariff at which electricity must be sold over a project's lifetime to recover all costs including capital, operations, maintenance, financing, and taxes, expressed on a per-kilowatt-hour (kWh) basis.

The LCOE is calculated as:
$LCOE = (I_0 + \Sigma[(M_t + F_t)/(1+r)^t]) / \Sigma[E_t/(1+r)^t]$

Where:
- I_0 = Initial capital investment (₹)
- M_t = Operation and maintenance costs in year t (₹)
- F_t = Fuel costs in year t (₹ - typically zero for solar/wind)
- E_t = Electricity generation in year t (kWh)
- r = Discount rate (%)
- t = Project year
- n = Project lifetime (typically 20-25 years)

Illustrative Case: 25 kWp solar mini-grid

Project configuration and cost assumptions

A standard 25 kWp solar photovoltaic mini-grid is considered to assess lifecycle costs under varying financial structures. The system requires an initial capital investment of Rs 31,50,000 and is designed to generate 33,000 kWh annually, with output declining at 0.7 per cent per year due to module degradation. The project life is assumed to be 25 years, with a discount rate of 12 per cent.

Operating expenses reflect realistic rural deployment conditions. Annual O&M costs begin at Rs 8,000 and escalate at 3 per cent annually. Operator or technician remuneration is Rs 1,00,000 in the first year, increasing at 5 per cent annually to reflect wage inflation. Land rent is Rs 12,000 per year with a 3 per cent escalation. A battery replacement costing Rs 5,50,000 is required in Year 10.

These assumptions represent a technically viable but financially sensitive rural mini-grid model.

Financing scenarios

To evaluate the influence of capital structure, three financing scenarios were modelled, representing the spectrum from purely commercial to highly concessional finance.

(i) Scenario 1: Commercial debt financing

This structure assumes 100 per cent debt at 9 per cent interest with a 12-year tenure. Annual debt servicing amounts to Rs 4,30,176. This scenario reflects a developer relying on standard commercial bank financing without concessional support.

Under these assumptions, the LCOE is Rs 14.41 per kWh, establishing the baseline for comparison.

(ii) Scenario 2: Blended finance

This structure combines multiple capital sources:

- 25 per cent grant (Rs 7,87,500)
- 25 per cent DFI loan at 4 per cent (Rs 7,87,500)
- 50 per cent private equity at 12 per cent (Rs 15,75,000)

The annual DFI debt service is Rs 82,737, while equity requires annual returns of Rs 1,89,000 over 25 years.

The blended structure reduces LCOE to Rs 12.10 per kWh, representing a 16 per cent reduction compared to commercial financing. However, financing costs remain substantial, particularly equity returns.

(iii) Scenario 3: Maximum concessional finance

This structure maximizes concessional support:

- 50 per cent grant (Rs 15,75,000)
- 50 percent DFI loan at 4 percent (Rs 15,75,000)
- No equity return requirement

Annual DFI debt service is Rs 1,65,475. Under this model, the LCOE declines to Rs 8.76 per kWh, a 39.2 per cent reduction from the commercial baseline.

Table 2: LCOE summary

Scenario	LCOE (₹/kWh)	Cost reduction
Scenario 1: Commercial debt	Rs 14.41	Baseline
Scenario 2: Blended finance	Rs 12.10	16.0% lower
Scenario 3: Concessional finance	Rs 8.76	39.2% lower

The analysis demonstrates that concessional finance and grant support are not optional add-ons but structural necessities for mini-grid viability. Feed-in tariffs, viability gap funding, DFI loans, and results-based financing each address a distinct layer of this financing gap, as explored further in Section 2.2.

2.2 Addressing the viability Gap: Subsidy mechanisms and blended finance

Even with optimal tariff design, mini-grids face an irreducible viability gap between cost-reflective tariffs of Rs 15–10 per kilowatt-hour and affordable domestic rates of Rs 5–8 per kilowatt-hour. No amount of regulatory sophistication can eliminate this fundamental economic reality. Rural electrification in low-income markets cannot achieve commercial viability through tariff revenues alone. Explicit subsidy mechanisms integrated with feed-in tariff frameworks become essential for bridging this gap.

Capital subsidies and results-based financing

Upfront capital grants represent the simplest subsidy approach. Governments or donors provide 30–50 per cent of project costs as non-repayable grant. This directly reduces the regulatory asset base and enables proportionally lower tariffs. Tanzania's Rural Energy Agency exemplifies this model, providing USD 100,000 business development grants plus USD 500 per connection to mini-grid developers as performance payments.[5] However, upfront grants create principal-agent problems. Developers may lack incentives to optimize costs or ensure sustained operations once funding is received.

Results-based financing has emerged as the dominant subsidy paradigm to address these principal-agent concerns. Under RBF, payments are contingent on verified delivery of specified outputs, typically connections or energy delivered. This shifts implementation risk to developers while ensuring public funds achieve intended outcomes. The structure typically includes output targets measured in connections or kilowatt-hours, payment triggers requiring independent

> Blended finance combines public, philanthropic, and private capital to support projects that deliver both social impact and financial returns. In India, decentralized solar mini-grids are well suited to this approach, especially in rural areas where grid extension is expensive and demand is modest. These projects face high upfront costs, long payback periods, and limited collateral, making conventional lending difficult. Blended structures use grants, viability-gap support, and concessional debt to absorb early risks and attract private investors. This reduces financing barriers, keeps tariffs affordable, and enables scale. In effect, blended finance helps channel private capital into reliable, inclusive energy access for underserved communities.

verification often using smart meter data, subsidy levels of USD 200–600 per connection or USD 0.10–0.20 per kilowatt-hour, and milestone-based timelines linking payments to commissioning and sustained operation rather than merely construction completion.

Nigeria's performance-based grant programme demonstrates RBF at scale. The program offers USD 600 per connection from a USD 48 million concessional facility.[6] Grants disburse in three tranches: 40 per cent upon materials arrival at construction sites, 40 per cent at commissioning, and final 20 per cent after 90 days of reliable electricity provision. By 2023, fourteen mini-grids were under development. Engie and CrossBoundary's landmark USD 60 million joint financing deal represents the largest mini-grid project finance transaction in Africa, expected to deliver electricity access to 150,000 beneficiaries by 2026.[7] The program requires minimum 70 per cent solar generation, explicitly prioritizing renewable-based rural electrification.

The Beyond the Grid Fund for Africa structures payments by project phase: 10 per cent at development milestone, 20 per cent at financial close, 40 per cent at commissioning, and final 30 per cent after twelve months of operations. This approach explicitly focuses on energy consumption rather than merely connections, incentivizing sustainable operations rather than connection-focused metrics that can produce non-functional systems.

Blended finance architecture

The most sophisticated approach employs three-layer capital structures that systematically reduce risk and cost of capital. The first layer comprises grant funding at 20–40 per cent of total project costs through results-based financing for connections and technical assistance, effectively reducing required equity. The second layer provides concessional debt at 30–50 per cent of financing through development finance institutions offering 10–15-year terms at 5–8 per cent interest with 2–3-year grace periods, often in local currency to eliminate foreign exchange risk. The third layer consists of commercial equity at 20–40 per cent from impact investors and corporate developers targeting 15–18 per cent returns, substantially reduced from the 20–25 per cent required without the risk mitigation provided by grants and concessional debt.

3. Regulatory Architectures for Integrating Mini-Grids into Central Grids

Feed-in tariff (FiT) frameworks often appear coherent in policy design but tend to fracture at the precise moment they matter most—when the national grid reaches a mini-grid service area. Grid arrival is the critical stress test: it exposes whether regulatory intent translates into workable transitions, whether investor assumptions hold, and whether decentralized assets remain commercially viable.

This chapter examines how Tanzania, Nigeria, Sri Lanka, Cambodia, and Indonesia have adapted FiT mechanisms to this transition risk, focusing on what happens to mini-grid assets, tariffs, and revenue streams once grid supply enters the market. Moving beyond statutory provisions, the analysis tracks operational reality: how licensing and tariff renegotiations unfold; how interconnection, franchise conversion, or exit options are executed; and whether compensation mechanisms function as intended or are undermined by delays and institutional ambiguity. Each case therefore assesses not only formal rules but also the coordination among regulators, utilities, developers, and communities required to manage grid arrival without eroding service continuity or investor confidence.

Electrification is shifting from linear grid extension to a 'network of networks'—centralized and decentralized systems as complementary infrastructure. For this to work, regulators need predictable frameworks, not discretionary decisions.

Three questions matter:

- What legal rights does a mini-grid developer hold once the central grid enters its service area?
- How are tariffs and revenue streams protected during transition?
- What becomes of generation assets, distribution networks, and customer relationships?

To ensure comparability, the regulatory architectures of the five countries are assessed through three uniform pillars:

(i) Market entry and licensing frameworks;

(ii) Tariff design and financial incentives; and
(iii) Interconnection and asset transition mechanisms

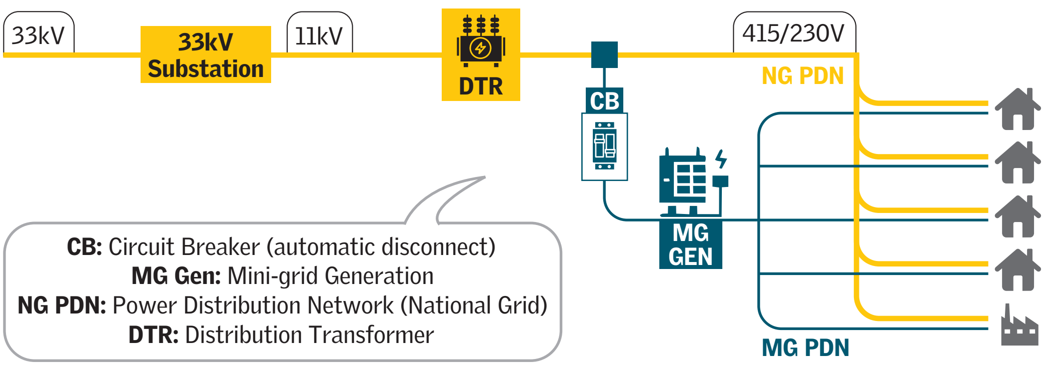
Across cases, the evidence suggests that regulatory clarity on paper is necessary but insufficient. Implementation credibility—honoured commitments, enforceable transition pathways, and demonstrated precedents—ultimately determines whether private capital flows at the scale required for sustainable rural electrification.

Mini-Grid Interconnection with the Main Grid: Options and Trade-offs

Let us understand the type of interconnection-

- The green lines represent the complete mini-grid system—generation assets and the mini-grid power distribution network (PDN)—which supplies electricity directly to households and commercial customers in the service area.
- Here, mini-grid infrastructure operates alongside the central grid, creating parallel distribution within the same geography. This already exists in parts of India, where private mini-grids function in areas technically connected to the main grid but suffering unreliable or inadequate supply.
- The mini-grid is also electrically interconnected with the main grid through an automatic disconnection mechanism (protection relay and breaker system) ensuring safety and regulatory compliance. This isolation capability—'islanding'—is mandatory under grid codes to prevent back-feeding during outages and protect maintenance personnel and system stability.

Figure 1: Mini-grid and grid connection schematic



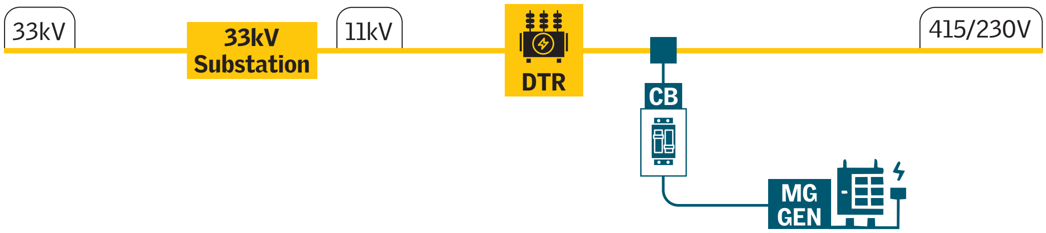
Option 1: Interconnection at the LT Network

One pathway is interconnecting the mini-grid at the low-tension (LT) distribution level—typically 415V (three-phase) or 230V (single-phase)—similar to rooftop solar systems. As shown in Figure 2, this positions the interconnection point closer to generation assets, reducing technical losses and minimizing capital expenditure for interconnection infrastructure.

However, LT interconnection requires several conditions: adequate local demand to absorb exported electricity; utility distribution infrastructure technically capable of integrating distributed generation at that node; and energized, operational rural feeder lines.

Stakeholder consultations indicate that in many rural Indian areas, the latter two conditions—robust distribution infrastructure and consistently live feeders—are often unreliably met, limiting LT-level interconnection viability.

Figure 2: Interconnection point on LT grid



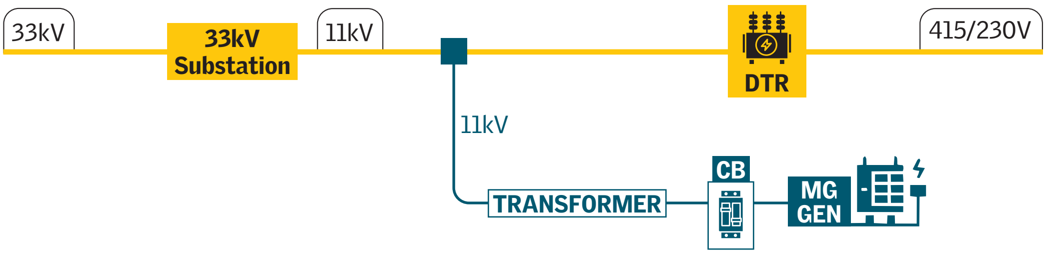
Option 2: Interconnection at the 11 kV Network

An alternative is interconnecting at the 11 kV medium-voltage network (see Figure 3). Some stakeholders argue utility infrastructure at 11 kV is more robust and better equipped for distributed generation.

However, most mini-grids generate and distribute at LT voltage. 11 kV interconnection requires a step-up transformer, and the nearest interconnection point is often several kilometres away, increasing cabling requirements.

Capital expenditure can be substantial. One expert estimated a transformer with approximately 5 km of cable could cost up to Rs 15 lakhs, excluding transformer and transmission losses. Under UPERC mini-grid regulations, operators bear this cost—often rendering 11 kV interconnections financially unviable for private developers.

Figure 3: Interconnection point at 11kV network



Bridging the DISCOM–developer divide

Fieldwork evidence from WRI India and the Transform Rural India Foundation's 2022 multi-stakeholder dialogue reinforces the urgency of regulatory coordination mechanisms between mini-grid developers and distribution companies (DISCOMs). DISCOMs frequently do not recognize the presence or contribution of mini-grids, and often perceive them as competitors rather than complementary infrastructure.

A central concern raised was the absence of publicly disclosed grid expansion plans or timelines from utilities. This information gap has cascading consequences. Mini-grid developers cannot make informed siting or investment decisions; communities receive contradictory signals about future electricity sources; and in several documented instances, infrastructure duplication has occurred in the same geographic area, inflating costs without improving access. More critically, when the grid does arrive without any prior coordination framework, mini-grids have become stranded assets overnight—systems that were functioning well, and in some cases providing superior reliability, rendered commercially unviable by the abrupt migration of customers to subsidized grid supply.

Yet practitioners at the dialogue were careful to distinguish mini-grids from the conventional grid on two dimensions that are often overlooked in policy debates: the *predictability* of supply and the *quality* of power for higher-load commercial and productive use applications, including three-phase connections. In regions where grid supply remains intermittent or voltage-unstable, some customers have continued to pay higher mini-grid tariffs specifically because the reliability premium justifies the cost differential. This customer behaviour underscores that the mini-grid–DISCOM relationship need not be a zero-sum competition; it can be structured as a complementary architecture where each serves distinct reliability and load segments.

The dialogue also surfaced the technical dimensions of interconnection that any coordination framework must address. Meaningful grid integration is complicated by challenges including safe interconnection at correct frequency and phase, inconsistent voltage and frequency regulation across systems, intermittent generation causing grid instability, and the need for specialized hybrid inverters capable of both exporting power and operating without the grid as a reference. These are not insurmountable barriers, but they require deliberate engineering standards, procurement specifications, and regulatory definitions that are currently absent from most Indian state mini-grid frameworks.

Practitioners identified four concrete integration pathways that coordination mechanisms should formally enable: operating in parallel to the conventional grid through separate distribution networks, selling electricity to the grid at regulator-approved tariffs, functioning as energy service companies for DISCOMs in areas where direct utility operation is not economical, and executing structured asset transfers to DISCOMs at agreed valuations when exit becomes necessary. Each of these options has analogues in international frameworks—Nigeria's Tripartite Agreement, Cambodia's small power distributor model, and Tanzania's SPP architecture—as examined in Chapter 3. The Indian regulatory environment currently provides no structured pathway for any of these transitions, leaving outcomes to ad hoc negotiations that consistently favour the DISCOM.

The entry points for action identified by dialogue participants align closely with the near-term regulatory priorities outlined in this chapter. First, regulators and DISCOMs must publish and maintain accessible grid expansion roadmaps, enabling mini-grid developers to factor grid arrival timelines into investment decisions. Second, state electricity regulatory commissions should mandate formal coordination protocols— analogous to Nigeria's consent requirement before a developer enters a licensed Disco territory—that require DISCOMs to either confirm absence from their five-year expansion plan or provide written no-objection before mini-grid commissioning. Third, dispute resolution mechanisms must be established to settle conflicts between DISCOM territorial claims and mini-grid operational rights, reducing the current dependence on informal negotiation that disadvantages smaller developers. These institutional mechanisms, grounded in practitioner experience from Jharkhand and other Indian states, provide the foundational coordination layer without which even well-designed feed-in tariff frameworks will fail to deliver investor confidence or service continuity.

Case Study 1
Nigeria: The tripartite model

Nigeria has developed one of the most comprehensive regulatory environments for mini-grids, specifically targeting 'undergrid' areas—communities that have physical distribution infrastructure but receive poor service from their local distribution company (Disco).

- **Market entry and licensing framework:** The Nigerian Electricity Regulatory Commission (NERC) utilizes a tiered approach to market entry. Systems with an installed capacity under 100 kW can choose to simply register their project, whereas those between 100 kW and 1 MW are required to obtain a formal permit[8]. For mini-grids operating in underserved areas already licensed to a Disco, the regulatory architecture centres on a Tripartite Agreement. This agreement is a formal contract signed by the developer, the local Disco, and the community, which serves as an example of 'regulation by contract'. The permit grants the developer a sub-concession to provide service, usually for a term of 20 years. Under these rules, a Disco must either confirm a community is not in its 5-year expansion plan or give written consent to the developer to enter the territory.
- **Tariff design and financial incentives:** Retail tariffs are set using a standardized multi-year tariff order (MYTO) model, a cost-of-service methodology that ensures developers can recover capital expenses (CAPEX) and operating expenses (OPEX) while earning a performance-related profit margin. To bridge the gap between high generation costs and customer affordability, the Rural Electrification Agency (REA) provides performance-based grants (PBGs). These grants were historically set at USD 350 per connection and later increased to USD 600, though they are currently set at approximately USD 450 disbursed in US dollars to protect developers from local currency volatility. The NERC regulations also allow for a "willing buyer/willing seller" tariff model for systems under 100 kW, provided the community agrees to the price.
- **Interconnection and asset transition:** The Nigerian framework specifically defines interconnected mini-grids as those connected to a Discom network to facilitate bulk power purchases or sales. Mini-grids often lease the Discom existing poles and wires via a Distribution Use of System (DUOS) charge, typically ranging from USD 0.006 to USD 0.013 per kWh sold. If the Disco eventually chooses to 'reintegrate' the community and take back retail control, the regulations provide a mandatory compensation formula. The developer is entitled to the remaining depreciated value of the assets plus an amount equal to the revenue generated in the 12 months preceding the takeover. This ensures that the private investment is not stranded when the main grid arrives.

Case Study 2
Cambodia: The distribution franchisee model

Cambodia is uniquely successful in transitioning a vast number of isolated private systems into a unified national structure through a model that focuses on distribution rather than generation.

- **Market entry and licensing framework:** The Electricity Authority of Cambodia (EAC) issued long-term distribution licenses (typically 5 to 20 years) to private entrepreneurs who had originally built isolated diesel-powered grids. To maintain these licenses, the regulator used a 'stick' approach, requiring operators to invest in 'grid-ready' infrastructure—standardizing poles and wires to EdC (national utility) standards—years before the central grid arrived. Once the central grid reaches the area, the EAC converts the combined generation and distribution licenses into pure distribution licenses, effectively turning the mini-grid into a small power distributor (SPD).
- **Tariff design and financial incentives:** Initially, mini-grids charged high, cost-reflective tariffs ranging from USD 0.40 to USD 1.00 per kWh. In 2016, the government transitioned to a uniform standard national tariff to ensure rural customers paid the same as urban ones. Because these mandated tariffs were often below the cost of service, the government implemented an ongoing operational subsidy. The EAC calculates a project-specific 'full cost-recovery tariff' annually for each licensee and pays the difference between that and the standardized retail price from a rural electrification fund capitalized by national utility profits.
- **Interconnection and asset transition:** Over 250 isolated mini-grids have interconnected as SPDs, serving more than one million customers. The transition is technically uncomplicated because power flow is unidirectional; the SPD abandons its own diesel generation and buys bulk power from the national utility or cross-border suppliers at wholesale. This model is commercially viable because the difference between the bulk supply tariff and the retail tariff (the distribution margin) is wide enough for a well-run SPD to be profitable. The national utility benefits from this arrangement because it avoids the high personnel and capital costs of building and managing last-mile rural retail networks.

Case Study 3
Tanzania: The SPP and third-generation rules

Tanzania pioneered a technology-neutral framework designed to incentivize both isolated and grid-connected renewable energy projects through 'light-handed' regulation.

- **Market entry and licensing framework:** Tanzania adopted a 'third-generation' licensing framework in 2017 that allows for portfolio licensing; a single license or registration can cover mini-grids at multiple locations using the same technology. Systems with a capacity below 100 kW are exempt from most formal licensing and tariff reviews, allowing them to operate on a 'willing buyer/willing seller' basis. For larger systems above 1 MW, a full license is required, while systems between 100 kW and 1 MW only require registration.
- **Tariff design and financial incentives:** The original financial mechanism utilized a technology-neutral feed-in tariff (FiT) that initially favored low-cost hydro and biomass projects. Regulations allow mini-grid operators to charge tariffs above the national utility rates, provided they are cost-reflective and approved by the Energy and Water Utilities Regulatory Authority (EWURA). However, this framework has faced significant political risk. In 2020, the government abruptly ordered mini-grid operators to reduce their tariffs by 75 per cent to 97 per cent to match the highly subsidized rates of the Tanzania Electric Supply Company limited (TANESCO), creating significant uncertainty for private investors[9].
- **Interconnection and asset transition:** Tanzania's small power producer (SPP) framework allows mini-grids to sell all or only excess power back to the national utility. A critical feature of the Tanzanian architecture is the ability of grid-connected mini-grids to operate in 'islanded mode' during main grid outages, providing superior reliability to rural customers. Compensation rules exist if the main grid encroaches on a mini-grid's territory, based on a capital cost measure adopted by the Rural Electrification Agency for distribution equipment. However, the lack of a dedicated fund to pay these compensations remains a hurdle to implementation.

Case Study 4: Kenya: The Hybrid PPP Model

Kenya has developed a regulatory architecture that balances top-down government planning with private sector participation, centring on a public-private partnership (PPP) framework in which the national utility retains long-term control while a separate bottom-up pathway exists for private developers in remote areas.

- **Market entry and licensing framework:** The Rural Electrification Agency (REA) and the national utility, Kenya Power and Lighting Company (KPLC), designate specific sites for development through competitive bidding, currently targeting approximately 120 mini-grids across 14 underserved northern counties. Bottom-up development by private developers is permitted but restricted to areas outside a 15-kilometre buffer zone surrounding existing medium-voltage lines. The licensing framework is tiered by scale: systems below 3 MW require a permit, while those above 3 MW require a full license. Despite this structured framework, the process is noted for significant administrative delays, with surveys indicating that obtaining all necessary approvals can take between 38 and 80 weeks, materially increasing project risk and deterring smaller developers.

- **Tariff design and financial incentives:** In the government-led PPP model, mini-grid customers pay uniform national retail tariffs identical to those charged by KPLC on the main grid from the first day of connection. Because these uniform tariffs typically do not recover the higher cost of serving dispersed rural populations, the revenue shortfall is covered through cross-subsidization from KPLC's broader customer base. Connection costs are additionally supported through the last mile connectivity program (LMCP), a World Bank-funded initiative providing per-household connection subsidies directly to KPLC. Winning private developers do not set their own retail rates; instead, they sell bulk power to KPLC under a standardized Power Purchase Agreement (PPA), with KPLC assuming the retail interface with end customers.
- **Interconnection and asset transition:** Kenya's model is explicitly designed as a transitional arrangement. Developers build, own, and operate mini-grid generation facilities for an initial concession period of seven to 10 years, during which they also construct and maintain the distribution network and perform billing and collections as a formal agent of KPLC. At the conclusion of the concession term, KPLC assumes full ownership and operational control of both generation and distribution assets. The model is structured for 'day one' grid integration in regulatory terms—KPLC functions as the official retailer even where the system operates in physical isolation from the national grid—ensuring that eventual physical interconnection requires minimal contractual or institutional restructuring.

Case Study 5
Sri Lanka: Transitional community-owned grids

Sri Lanka's experience is defined by a historical reliance on community-owned organizations that were viewed as temporary solutions until the national grid could achieve universal access.

- **Market entry and licensing framework:** Electrification was driven by electricity consumer societies (ECSs), which were registered as nonprofit social welfare organizations. This status allowed them to operate without the formal commercial licenses required for private companies. However, this legal status became a barrier to integration because an ECS, as a welfare society, lacked the legal authority to sign commercial contracts with the national utility (CEB). To interconnect, an ECS must reconstitute as a registered village cooperative or a limited liability company (LLC).

- **Tariff design and financial incentives:** ECSs set their own retail tariffs, but these were typically too low to fund depreciation or asset replacement because community members were unwilling to pay cost-reflective rates. The program was supported by performance-based grants of USD 400 per kW of installed capacity, up to a maximum of USD 20,000. Once the national grid arrived, it offered highly subsidized lifeline tariffs (USD 0.017 to USD 0.067 per kWh), which were roughly 10 times lower than the ECS costs, rendering most societies economically unsustainable.
- **Interconnection and asset transition:** Mini-grids can legally transition to Small Power Producers (SPPs) by signing a standardized power purchase agreement (SPPA) with the CEB. As SPPs, they sell their entire output wholesale to the utility and stop providing retail service to villagers. However, this transition is rare; by 2016, only three out of 250 ECSs had successfully converted. Barriers to conversion include the high 'soft costs' of environmental clearances and load flow studies required by the utility, which often exceed the value of the electricity produced by small (under 100 kW) systems.

Case Study 6
Indonesia: The PSK tersebar framework

Indonesia's regulatory architecture has adapted to its unique archipelago geography, focusing heavily on decentralized micro-hydro power as a precursor to grid extension.

- **Market entry and licensing framework:** The 2009 Electricity Law permits private sector and cooperative participation in generation and distribution but grants the state utility (PLN) the 'right of first priority'. Market entry for renewable systems under 1 MW is governed by ministerial decrees known as PSK Tersebar. Most mini-grids are managed by local community-based organizations, with assets often owned by the district or provincial government. Historically, a major hurdle was a regulation that prevented government-funded projects from selling power to the national utility to prevent private gain from state assets.
- **Tariff design and financial incentives:** Indonesia uses standardized feed-in tariffs based on PLN's location-specific generation costs. For low-voltage interconnections, the FiT was originally set at 60 per cent of PLN's base price. Developers frequently criticized these tariffs as too low (approximately USD

0.03 to USD 0.04 per kWh) to cover operating expenses. In 2017, new decrees were issued to refine these tariffs, denominating them in US dollars and establishing a 20-year power purchase agreement for micro-hydro projects.

- **Interconnection and asset transition:** A 2017 ministerial decree removed a critical barrier by explicitly allowing government-funded micro-hydro projects to legally interconnect and sell electricity to PLN. Operators have two primary options: Selling all output as a pure SPP, or selling only excess output while continuing to serve the local village at retail (the SPP + SPD model). While 150 projects were abandoned upon grid arrival, the nine projects that successfully interconnected have served as technical pioneers for synchronization standards and equipment, with locally manufactured synchronization panels costing approximately USD 6,000.

Site-specific case studies

Case A: The Toto Interconnected Mini-Grid (Nigeria)

- **Regulatory arrangement:** This project operates under a tripartite agreement with the Abuja Electricity Distribution Company (AEDC). The developer, PowerGen, invested approximately USD 500,000 to refurbish the Discom dilapidated distribution grid, representing 25 per cent of the total project cost.
- **Integration outcome:** The system is designed to supplement its solar generation with six hours of firm (guaranteed) power purchased from the DISCOM during night, when solar generation is unavailable. This guaranteed bulk supply allowed the developer to reduce initial battery storage requirements, lowering capital costs by an estimated 15–20 per cent and reducing the levelized cost of electricity by 10 per cent. PowerGen commits to 95 per cent availability for its customers under this arrangement.

Case B: Wuse Market Interconnected Mini-Grid (Nigeria)

1. **Regulatory arrangement:** Located in Abuja's largest urban market, this project is a subconcession agreement between GVE (developer), AEDC (Disco), and the traders' association. GVE assumed all retail obligations, including metering and maintenance, for over 2,000 shops.
2. **Integration outcome:** The mini-grid purchases seven hours of firm nightly electricity from the Disco. By replacing over 3,000 individual, polluting diesel generators, the project reduced shopkeepers' energy costs from a blended price of USD 0.38/kWh to a regulated tariff of USD 0.133/kWh—a savings of roughly 65 per cent.

Case C: Seloliman Micro-Hydro Project (Indonesia)

- **Regulatory arrangement:** Originally established as a 12-kW standalone system in 1994, it became the first project to interconnect under the PSK Tersebar regulation after expanding to 30 kW. It operates as an 'excess only' SPP.

- **Integration outcome:** The project continues to serve the village at retail but sells surplus electricity wholesale to the national utility at approximately USD 0.05 per kWh. It generates roughly USD 9,700 in annual revenue, which the village cooperative has used to fund the development of a second hydropower plant downstream.

4. Policy recommendations and future outlook

4.1 Learning from the global mini-grid experience

India faces a pivotal moment in mini-grid policy. The failure of over 100 systems across West Bengal, Chhattisgarh, Bihar, and other states has left crores in stranded assets—a stark reminder that technical viability means little without robust regulatory frameworks. However, international experience offers a roadmap forward. Tanzania, Nigeria, Kenya, and Indonesia have shown that feed-in tariffs coupled with grid integration protocols can transform mini-grids from high-risk ventures into bankable infrastructure. The challenge now is adapting these proven models to India's federal structure and renewable energy expansion, requiring coordinated policy action across multiple institutional levels and timescales.

Grid integration has emerged as a critical policy priority. As conventional electricity networks expand into mini-grid service areas, regulators have developed four pathways for operators to choose from:

a. **Parallel operation** — Continue serving customers through a separate distribution network that operates alongside the conventional grid, particularly relevant where grid reliability remains poor
b. **Independent power producer** — Shift from retail distribution to wholesale generation, selling electricity to the main grid at regulator-approved rates
c. **Energy service company** — Become a contracted operator for distribution utilities, managing last-mile networks in areas where direct utility operation isn't economically viable
d. **Asset transfer and exit** — Sell physical infrastructure to the local distribution company at negotiated valuations following Nigeria's investor-protection formula of depreciated book value plus twelve-month revenue equivalent

Each pathway addresses different operator capabilities and market conditions, providing flexibility while maintaining service continuity as grid infrastructure expands.

Near-term priorities: Establishing regulatory clarity

Indian regulators at both central and state levels must prioritize establishing clear legal and regulatory frameworks that resolve fundamental uncertainties deterring private investment. While the 2016 National Tariff Policy amendment requiring distribution companies to purchase power from mini-grid operators represents important progress, implementation remains patchy across states. Learning from Nigeria's capacity-based regulatory thresholds, India should consider establishing simplified registration pathways for systems below 100 kilowatts, exempting them from detailed permitting while requiring only community consensus and basic technical standards compliance. Systems between 100 kilowatts and one megawatt could follow streamlined 30–45 day approval processes using standardized tariff calculation tools, while larger installations undergo full regulatory determination with power purchase agreement negotiations.

State Electricity Regulatory Commissions should develop and publish transparent tariff-setting methodologies with worked examples that allow developers to model project economics before committing resources to site development and licensing applications. The Excel-based AFUR Mini-Grid Tariff Tool, successfully adapted across multiple African countries, provides an open-source starting point that Indian regulators could localize within months[10]. Transparency in tariff calculation eliminates information asymmetries that currently force developers to navigate uncertain approval processes, builds stakeholder confidence, and reduces regulatory discretion that creates corruption risks. States like Uttar Pradesh, Bihar, and Odisha that have announced mini-grid policies but lack operational tariff determination frameworks could adopt and customize these proven methodologies rather than developing entirely novel approaches consuming years in drafting and consultation.

India should formally codify these four pathways in state mini-grid regulations, drawing on the compensation mechanisms and transition frameworks examined across the international case studies in Chapter 3.

Medium-term priorities: De-risking investment through blended finance

Medium-term priorities must centre on market facilitation and capacity building that address ecosystem gaps constraining sector growth beyond purely regulatory barriers. Even excellent regulations cannot catalyze investment if developers lack access to appropriate financing, technical expertise, or reliable supply chains. Learning from Tanzania's Rural Energy Agency credit line and Nigeria's Rural Electrification Agency financing programs, India should establish dedicated mini-grid financing facilities combining results-based grants, concessional debt, and first-loss guarantees. The three-layer blended finance architecture successfully deployed in African markets—combining grant funding at 20–40 per cent of costs, concessional debt at 30–50 per cent, and commercial equity at 20–40 per cent—should inform Indian financial product design.

Results-based financing represents the dominant international subsidy paradigm precisely because it addresses principal-agent problems where upfront grants may not incentivize sustained operations. India should implement RBF programs offering Rs 30,000–50,000 per connection paid upon verified commissioning and six-month reliable operation, combined with upfront capital subsidies covering 30–40 per cent of project costs. Payment structures should follow the Beyond the Grid Fund for Africa model: 10 per cent at development milestone, 20 per cent at financial close, 40 per cent at commissioning, and final 30 per cent after twelve months of operations, explicitly focusing on energy consumption rather than merely connections to incentivize sustainable operations rather than connection-focused metrics producing non-functional systems.

Technical capacity building encompasses both developer capabilities and regulatory expertise. Many Indian states possess entrepreneurial energy but lack the engineering, financial modelling, and project management skills required to develop bankable mini-grid projects. Structured technical assistance programs delivered through industry associations like India Smart Grid Forum or academic institutions can rapidly upgrade local developer capacity, enabling domestic enterprises to compete with international firms while retaining more project value within the national economy. Simultaneously, State Electricity Regulatory Commissions require specialized expertise in mini-grid economics, tariff analysis, and performance monitoring to effectively implement FiT frameworks. Dedicating staff positions specifically to mini-grid regulation, providing specialized training through exchanges with African regulators managing mature frameworks, and facilitating knowledge sharing builds institutional capacity essential for effective oversight.

Long-term vision: Storage integration and grid services

The long-term vision extending toward India’s 2030 universal electrification targets requires systemic integration of mini-grids into national energy planning frameworks. India’s December 2025 regulatory breakthrough, which treats energy storage as transmission infrastructure and enables virtual transmission and grid-balancing services, creates new opportunities for mini-grid integration. Instead of grid arrival leading to system abandonment, it could enable a transition to integrated distribution franchises, where mini-grids continue serving local loads while their storage capacity participates in wholesale balancing markets.

States have collectively tendered over 13 gigawatt-hours of battery storage for grid-support services that mini-grids inherently deliver. Systems ranging from 100 kilowatt-hours to several megawatt-hours already possess the operational characteristics utilities are procuring through separate storage tenders. Policymakers should actively promote mini-grid integration into grid operations through appropriate technical standards, grid codes accommodating bidirectional power flows, and tariff structures compensating ancillary services provision including frequency regulation, voltage support, and renewable energy firming. This transforms grid arrival from existential threat into value-creating transition, ensuring investments in mini-grid infrastructure retain productive value throughout technical lifespans regardless of main grid expansion timing.

Implementation imperative: From policy to action

The pathway ahead requires sustained political commitment, adequate financing, and coordinated action across central government, state regulators, distribution companies, private developers, and rural communities. However, the technical solutions, business models, and policy frameworks enabling successful mini-grid deployment are increasingly well-understood and proven across diverse international contexts. The challenge now is implementation at the scale and pace required to achieve universal energy access while supporting broader sustainable development and climate objectives. The policy choice facing Indian regulators is stark: continue allowing mini-grids to operate in regulatory vacuum subject to displacement without compensation, perpetuating the cycle of stranded assets documented across multiple states, or recognize them as permanent distributed infrastructure warranting the same regulatory protection and integration planning afforded to utility-scale generation. Global experience provides the roadmap—India must now demonstrate the political will to implement it.

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India has over 100 defunct mini-grids representing crores in stranded assets—not because of technical failure, but due to a policy vacuum. When the national grid arrives, otherwise functional mini-grids collapse. There are no feed-in tariffs allowing them to sell power, no buyout mechanisms to protect investments, and no franchise models to preserve their distribution infrastructure.

This report examines how Tanzania, Nigeria, Kenya, Indonesia, and Sri Lanka have solved this through adapted feed-in tariff frameworks. It translates international evidence into actionable Indian policy: how to design tariffs, manage grid arrival, value battery storage as grid infrastructure, and transform mini-grids from risky ventures into bankable, integrated assets within India's expanding renewable energy system.

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