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Not Too Much, Not Too Little

A Goldilocks Approach to Sustainable, Universal Electricity Access in Sub-Saharan Africa

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Abstract

This paper proposes a replicable regulatory and financial framework to achieve universal electricity access as a core component of a just energy transition in Sub-Saharan Africa. It argues that universal access is feasible under realistic constraints when electrification planning, tariff regulation, and capital mobilization are designed as one coherent system rather than separate workstreams. The analysis rests on a computational, multi-period financial model that integrates individual interacting sub-models for every actor in the distribution segment. Versions of the same overall approach are applied to three countries, spanning different starting points and sector structures. Uganda provides the reference implementation in the wake of an expiring private distribution concession; Zambia recalibrates the same logic to a distressed national utility and a thin domestic revenue base; and Madagascar—where the framework is already being applied—shows it moving from design to district-scale delivery in the lowest electricity access setting of the three. The central mechanism is an integrated national planning, regulatory, business, and financing architecture that coordinates grid extension, mini-grids, and stand-alone systems within a single distribution-level financial plan. The framework separates two gaps that are routinely mixed—the viability gap, the recurring shortfall between affordable tariff revenues and the regulated cost of service, and the financing needs, the timing mismatch between front-loaded investment and gradual cost recovery—and shows that they each call for a distinct instrument. The evidence indicates that universal access can be reached without permanent reliance on external grants, and that extending the access horizon rather than compressing investment improves feasibility while still reaching everyone—so that the design becomes a problem of finding an electrification target year, a pattern of overall subsidy, and tariffs that are just right, each neither too much nor too little. The paper reframes universal access as a challenge of cost allocation and institutional design, showing that affordability, inclusion, and financial sustainability are not competing objectives once electrification is designed as one system.

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A Goldilocks Approach to Sustainable, Universal Electricity Access in Sub-Saharan Africa

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1. Introduction

The dominant framing of the energy transition equates it with decarbonization: replacing fossil generation, electrifying end uses, and bending emissions curves downward. For the roughly 600 million people who still lack any electricity supply, that framing is incomplete. Their transition is not, in the first instance, a shift away from carbon; it is the acquisition of a service they have never had. Any account of a just energy transition that does not place this population at its center risks reproducing the very inequities the transition is meant to redress. This paper therefore treats universal electricity access as constitutive of, not adjacent to, the transition agenda in Sub-Saharan Africa.

The argument is organized around three premises. The first is that access to electricity is a basic service, not an optional investment. Electricity is a precondition for health, education, productive employment, and participation in modern economic life; its absence is concentrated among the rural poor, and reaching them is as much about delivering an essential service as about building infrastructure. The second premise is that the access deficit is not, at its core, a technical problem. Geospatial planning can already determine, village by village, the least-cost mix of technologies needed to reach every household; what is missing is the regulatory and financial architecture that turns those plans into financeable programs. The deficit is, in this sense, a regulatory–financial problem wearing the costume of an engineering one. The third premise is that there is no single recipe. The binding constraint differs across countries—an expiring concession in one, a distressed incumbent utility in another, a thin domestic revenue base in a third—and a framework worth the name must be a method for diagnosis and calibration, not a template to be copied.

The scale of the challenge is well established. Under prevailing policies, the International Energy Agency projects that 645 million people will still lack electricity in 2030, with more than 85 percent of them in Africa (IEA, 2025a; IEA et al., 2024). Meeting the 2030 access target would require connecting roughly 90 million people a year on the continent—about three times the historical rate—and mobilizing on the order of USD 25 billion annually this decade, a figure that is less than 1 percent of global annual energy investment, yet far above current commitments, which have declined in real terms (IEA, 2022). The binding obstacles are not only the quantum of capital but its cost: risk premiums and interest rates on African power projects run two to three times those of advanced economies, eroding bankability and steering whatever private finance does arrive toward generation rather than the distribution networks on which access directly depends (Briera and Lefèvre, 2024; IEA, 2023).

Against this backdrop, the paper poses a single question: under what regulatory, contractual, and financial conditions can a least-cost electrification plan become implementable, financeable, and inclusive (i.e., it leaves no one behind)? The answer developed here is that planning must be coupled to a credible cost-recovery regulation and business model with an explicit treatment of affordability, and a financing structure that can absorb front-loaded rollout without breaching bankability—and that all three must be designed together. The unifying idea is one of calibration, and it gives the paper its title. The approach to electrification access that is proposed here has a *Goldilocks* quality: a pace compressed into a few years can render financing infeasible and overwhelm institutional capacity, while a pace stretched too far condemns the last households to wait a generation; a subsidy set too high wastes scarce public resources and crowds out private capital, and one set too low leaves the service unbankable; a tariff fixed too high is unaffordable, while one fixed too low abandons cost recovery altogether.[1] In each dimension the task is not to maximize or minimize but to find the right value or range that is neither too much nor too little. The analysis that follows is, throughout, a search for those "just right" values in each country—not a menu of options to choose among, but a single calibrated design fitted to local conditions.

The remainder of the paper proceeds as follows. Section 2 diagnoses the implementation gap that separates technically optimal plans from financeable programs. Section 3 develops the integrated regulatory–financial architecture that is the paper's analytical core, including the two distinct gaps that bind implementation and the pooled financing vehicle that addresses them. Sections 4, 5, and 6 apply the framework to three countries: Uganda, a fully worked reference case in the wake of the Umeme concession; Zambia, where the same logic is recalibrated to a distressed national utility; and Madagascar, where the framework is already being implemented at district scale as the *Cadre d'Électrification Rurale Intégrée*. Section 7 distills what is invariant across the three applications from what must be calibrated to context. Section 8 offers actionable recommendations and concludes.

2. The implementation gap: Why least-cost plans stall

A national least-cost plan is necessary for universal access, but it is not sufficient for it. The gap between the two has a recognizable anatomy, and naming its parts is the first step toward closing it.

2.1. Least-cost is not the same as implementable

Over the past decade, geospatial optimization has matured into a powerful planning instrument. Tools such as the Reference Electrification Model (REM) (Ciller et al., 2019) and comparable platforms characterize demand, population density, terrain, and existing infrastructure, and then select—for each locality—the option that minimizes life-cycle cost among grid extension, mini-grids, and stand-alone solar systems (Ciller and Lumbreras, 2020). The outputs are coherent national roadmaps, and development finance institutions have underwritten more than forty such master plans. Yet

[1] The allusion is to "Goldilocks and the Three Bears," the English children's story in which a young girl named Goldilocks tries three bowls of porridge—one too hot, one too cold, one just right—and settles on the one in between. The term has since come to denote not a fixed optimum, but a setting judged right for its circumstances—neither too much nor too little. That is the sense intended here: the proposed framework is a single architecture applied through a different recipe in each country, so that the outcome is not a comfortable compromise but a plan capable of reaching universal access at scale and sustaining it without permanent reliance on grants. Refer to https://en.wikipedia.org/wiki/Goldilocks_principle.

independent diagnostics find that barely half of access-deficit countries even have an approved plan in force, and far fewer have translated those documents into networks and connections (World Bank, 2025, 2020). The roadmaps look optimal on paper and prove non-executable in practice.

The reason is structural. These models typically assume a single, uniform cost of capital across all technologies and overlook the financial constraints of utilities and governments; most do not integrate business-model selection, existing regulation, financing strategy, or consumer affordability into the optimization (Agutu et al., 2022). The omission is not innocuous. Incorporating realistic differences in the cost of capital can shift hundreds of millions of people from being optimally served by mini-grids to being more cheaply served by stand-alone systems (or even grid extension)—an outcome invisible to any model that assumes concessional finance for every technology (Agutu et al., 2022).

2.2. Three business models, one financial framework

A second failure follows from how the sector is organized conceptually and institutionally. Grid extension, mini-grids, and stand-alone systems are not separate worlds but three electrification modes for serving a single distribution problem—each with its own cost structure, regulation, business model, revenue logic, and risk profile. Too often, though, they are organized as if they were unrelated—different ministries, different funding windows, different developers, different rules—rather than integrated, above all financially. International experience consistently shows that integrated strategies outperform fragmented ones on both financial sustainability and allocative efficiency (Ankel-Peters et al., 2025; Falchetta et al., 2022). Fragmentation produces inconsistent subsidy rules, unstable disbursements, high transaction costs, and weak cross-subsidy logic; it also raises perceived risk, and therefore the cost of capital, sector-wide. Each business model must be bankable on its own terms, but all three should be integrated financially—under one coherent framework for financing, tariff design, and cross-subsidization, so that surpluses in low-cost segments can help fund service in high-cost ones (Briera and Lefèvre, 2024; CEER, 2020).

2.3. The affordability–bankability contradiction

The third element is the contradiction at the heart of distribution finance in low- and middle-income systems. Political mandates to hold tariffs below the cost of recovery create quasi-fiscal deficits, weaken utility balance sheets, and limit the capacity to invest or to serve as credible off-takers (Balabanyan et al., 2021; Kojima and Trimble, 2016; Trimble et al., 2016). The contradiction is genuine: tariffs that are affordable for newly connected rural households do not, on their own, remunerate the cost of serving them, while tariffs that would remunerate that cost are unaffordable and politically unacceptable. Extending uniform tariffs to high-cost, low-demand customers therefore increases costs faster than revenues, opening a deficit precisely as access expands. What must be cost-reflective, however, is not the end-user tariff but the remuneration of each activity and business model, with an explicit subsidy covering the difference. This is not a temporary inconvenience that can be easily overcome; it is the financial side of an affordability decision, and any framework that ignores this fact will fail.

2.4. "More and smart financing" is not the answer—at least not by itself

The intuitive response to an investment gap is to find more money or innovative financial instruments. This is the wrong diagnosis. Capital does not flow to the distribution segment because it does not generate predictable, contractually reliable cash flows. If subsidy disbursement is discretionary or delayed, providers cannot rely on stable inflows and the program becomes unbankable, regardless of the headline volume of available finance (Foster and Rana, 2020).

The binding constraint is therefore not the supply of capital or the design of clever financial structures, but the absence of bankable cash flows—and such cash flows are produced by regulation and contracts, not by funding announcements. Therefore, the primary intervention must be institutional: a credible commitment that converts the regulated cost of service into timely cash receipts for each implementing agent. Only against such a commitment can concessional and commercial capital be mobilized on affordable terms at scale.

2.5. Lessons learned from electrification strategies

Taken together, these failure modes imply four mutually reinforcing prerequisites for lasting electrification, each corresponding to a distinct way that plans fail. Formalized and empirically evaluated, these four prerequisites constitute the Integrated Framework for Electrification (IFE) (GCEEP, 2020; Pérez-Arriaga, 2024, 2023). The first is **cost-effective planning**: matching each locality to the least-life-cycle-cost technology, which lowers the total cost that must ultimately be recovered. The second is **scalability**, operationalized as a binding universal service obligation that commits providers to serve every household in a territory, not only the commercially attractive ones. The third is **financial sustainability**, achieved when a cost-reflective revenue requirement is recovered through a transparent mix of tariffs and explicit subsidies over the life of the assets. The fourth is **development-focused planning**, which links access to productive uses and demand growth so that revenues and welfare gains actually materialize. These are not an arbitrary checklist. They emerge from a single implementation problem: a least-cost plan becomes a program only when an implementing group of agents can deliver the technology portfolio at scale, under a binding mandate, recovering efficient costs through affordable tariffs plus governed transfers, while stimulating the demand that sustains it. When one pillar fails, the others lose traction. The architecture developed next operationalizes the IFE—the structure that holds the four together.

3. The integrated architecture

This section sets out the paper's' analytical core: a regulatory–financial architecture that completes least-cost planning by specifying who delivers the service, how their costs are recovered, and how the required capital is mobilized and secured. The architecture has five components—a universal service obligation, a cost-of-service regime, the separation of two distinct gaps, a utility-like treatment of off-grid supply, and a pooled financing vehicle—each of which is necessary and none of which is sufficient on its own.

3.1. The universal service obligation

The operational expression of political will to leave no one behind is the universal service obligation (USO): a legal duty, embedded in licenses, concessions, or equivalent instruments, to connect and serve all households in a defined territory to a defined standard. The USO defines service areas, access targets, quality standards, and enforcement mechanisms. Its importance is empirical, not merely normative. World Bank research shows that universal service obligations, when paired with targeted subsidies, accelerate rural electrification without undermining financial viability, and that regions operating under legally enforced obligations achieve higher connection rates at comparable cost than regions relying on discretionary expansion (Estache et al., 2006; Leduchowicz-Municio et al., 2022). Country experiences—Brazil's *Luz para Todos*, China's last-mile campaign, India's *Saubhagya*—confirm that binding obligations backed by dedicated funding turn electrification from a series of projects into a predictable multi-year program with clear accountability. Without the obligation, expansion stalls once the commercially attractive segments are exhausted; with it, the remaining task becomes a financing problem rather than a question of willingness (Arif, 2025; He, 2019; IEA, 2025b).

3.2. The cost-of-service regime and what "cost-reflective" actually means

Under cost-of-service regulation, the regulator sets, for each regulated entity *i* and each year *t*, an allowed **revenue requirement** intended to cover efficient costs and a reasonable return on invested capital:

$$\mathrm{RR}_{t,i}\,(=\,\mathrm{CoS}_{t,i})\;=\;\mathrm{OPEX}_{t,i}\;+\;\mathrm{DEP}_{t,i}\;+\;\mathrm{RAB}_{t,i}\times\mathrm{WACC}_{t,i} \qquad (1)$$

where OPEX is efficient operating expenditure, DEP is regulatory depreciation of the regulated asset base, RAB is that regulated asset base, and WACC is the weighted average cost of capital used to remunerate it (Gómez, 2013; Reneses et al., 2013). The choice to anchor the allowed return in the weighted average cost of capital rather than a generic "allowed rate of return" is deliberate: the WACC is the single parameter that most powerfully drives the return on the RAB and, through it, the revenue requirement and the resulting end-user tariff. It is also the channel through which the affordability–

bankability contradiction propagates, since a high perceived risk raises the WACC and inflates the revenue requirement that tariffs and subsidies must ultimately cover.

A point that is routinely misunderstood deserves emphasis. In this framework, "cost-reflective" refers to the **revenue requirement in aggregate, not to the end-user tariff**. Genuinely cost-reflective end-user tariffs—prices that, customer by customer, exactly recover the cost of serving each one—do not exist in practice in any power system, and least of all in one that extends a uniform national tariff to all rural and urban households. The regulatory objective is not that every customer pays the cost of their own supply; it is that each regulated entity *receives*, in cash and within the year, the allowed amount. Tariffs contribute to that cash flow, but where affordability prevents tariffs from reaching the cost-reflective level, the regime must specify an explicit mechanism that pays the difference. Conflating cost-reflectivity of the revenue requirement with cost-reflectivity of the tariff is one of the most consequential errors in access policy, because it leads governments either to impose unaffordable tariffs or to abandon cost recovery altogether.

3.3. Two gaps that bind implementation

The single most important analytical move in this paper is the separation of two gaps that have different economic meanings and require different treatment. Confusing them is a recurrent source of implementation failure.

The **viability gap** arises when affordability holds end consumer tariffs below the cost of service, so that realized cash revenues fall short of the revenue requirement:

$$\mathrm{VG}_{t,i} = \mathrm{CoS}_{t,i} - \mathrm{REV}_{t,i} \qquad (2)$$

where realized revenues REV depend on tariff levels, billed energy, losses, and collection performance. The viability gap is a **recurring revenue-adequacy problem**. If tariffs remain below the cost of service for prolonged periods without a credible compensation mechanism, the regulated business is structurally loss-making, private participation becomes unlikely, and even concessional lenders hesitate. The correct instrument is therefore an explicit, predictable, and enforceable compensation mechanism: a budget transfer, an access fund, a sector levy, an auditable cross-subsidy, or ring-fenced flows through a dedicated institution. What matters is not the legal form but the predictability: a viability gap funded by discretionary, in-arrears transfers raises risk, lifts the WACC, and ultimately increases the cost borne by consumers and taxpayers alike.

The **financing needs** gap arises even when the activity is viable in the long run, because electrification requires large upfront investment while regulated cost recovery occurs gradually:

$$\mathrm{FN}_{t,i} = \mathrm{TOTEX}_{t,i} - \mathrm{CoS}_{t,i} \qquad (3)$$

where total cash expenditure decomposes as:

$$\mathrm{TOTEX} = \mathrm{OPEX} + \mathrm{CAPEX} + \Delta\mathrm{NWC} + \mathrm{TAX} + \mathrm{DS} + \mathrm{DIV} \quad (4)$$

comprising operating costs, capital expenditure, working-capital changes, taxes, debt service, and dividends. The core driver is the intertemporal structure of cost recovery: the revenue requirement remunerates investment through depreciation and the allowed return spread over an asset's economic life, and therefore it does not reimburse a front-loaded cash outlay in the year it is incurred. The resulting timing wedge is not, by itself, evidence of regulatory failure—it reflects timing, not insolvency. Its correct instruments are accordingly different: capital structures, tenors, grace periods, sculpted amortization profiles, and liquidity and working-capital facilities aligned with the regulatory recovery horizon.

The practical force of the distinction lies in the failure modes of confusing the two. Financing a viability gap with debt—treating a structural revenue shortfall as if it were a liquidity bridge—loads debt service onto a business that cannot service it and drives it toward insolvency. Conversely, financing a financing needs gap with grants—treating a timing mismatch as if it were a permanent shortfall—over-subsidizes the program, wastes scarce concessional resources, and crowds out private capital that would willingly have funded a bankable cash-flow trajectory. The two gaps should be tracked and reported separately, against separate instruments, throughout the life of a program. Much of the diagnostic value of the framework consists in keeping them apart (Díaz-Pastor et al., 2026a, 2026b).

3.4. Utility-like obligations for off-grid electrification

The same principle applies to off-grid systems: access should be regulated as a continuing service obligation, not treated as the one-off deployment of equipment. The objective is to make decentralized supply "utility-like" in its obligations, not necessarily in its ownership, technology, or institutional form. This means that the provider is responsible for continuity of service, maintenance, replacement, customer support, and compliance with defined quality standards, while remuneration is structured so that those obligations can be financed over time.

Mini-grids and stand-alone solar home systems must be treated separately. A mini-grid is a local electricity system with generation, storage, and distribution assets serving several customers. A solar home system is an individual supply asset installed at the customer's premises. The technologies differ as well as the level of service provided, but the regulatory question is the same: who is obliged, and financially able, to keep the service running over time.

For mini-grids, the appropriate instrument is a regulated local concession (or equivalent Public-Private Partnership, PPP). The concession should define the service area, connection obligations, minimum service standards, quality and reliability requirements, reporting duties, consumer-protection rules, and the treatment of grid arrival. The concessionaire's remuneration should be based on the efficient cost of meeting those obligations. Customers would pay the applicable regulated tariff, or another regulated affordable tariff defined for this category of service. If that tariff is below the efficient cost of supply, the difference must be paid through an explicit viability-gap subsidy.

This is different from the prevailing project-finance model based mainly on an upfront capital subsidy. A capital grant can reduce the investment to be recovered, therefore reducing the required annual remuneration. But it does not, by itself, fund the continuing obligations of a mini-grid: maintenance, battery replacement, generation expansion, network reinforcement, new connections, and service-quality compliance. Those costs arise because the system is successful: demand grows, customers add appliances, and more households seek connection. A framework that funds construction but not renewal eventually forces one of three outcomes: tariffs rise beyond affordability, service quality deteriorates, or the operator exits.

The remuneration mechanism should therefore be defined in two layers. First, the customer tariff is set as a policy and regulatory decision. If the objective is parity with grid-connected customers, that parity should be stated explicitly as an affordability and non-discrimination choice, not as evidence that the mini-grid's cost is the same as the main grid's cost. Second, the operator's allowed revenue is determined separately, based on the efficient cost of providing the required service. The gap between tariff revenue and approved allowed revenue is the regulated subsidy.

Competitive tendering can be used to discipline this subsidy, but the tender object must be defined correctly. Developers should bid for a defined package of mini-grid obligations: identified sites or communities, connection targets, service standards, expansion requirements, and an initial regulatory period. The bid should reveal the minimum subsidy, or minimum allowed remuneration, required to provide the specified service under those obligations. After the initial period, adjustments should follow pre-defined regulatory rules: indexation, pass-throughs, performance penalties, efficiency reviews, and periodic resets where needed. The cost of capital should be set consistently with the concession's actual risk allocation, including demand risk, subsidy-payment risk, grid-arrival risk, and residual-value treatment. It should not be assumed independently of the capital structure that the concession can actually finance.

Grid-arrival and end-of-term rules must be fixed at the outset. If the main grid reaches a mini-grid area, the contract should specify whether the assets are integrated into the grid, transferred to the utility, operated as a distribution concession, or compensated. Compensation should be based on a defined measure of unrecovered regulated value, not negotiated after the event. Similarly, at the end of the concession, the assets should either be transferred, bought out, re-tendered, or retained under a renewed concession under rules known in advance. These provisions are central to bankability because they determine residual-value risk.

Solar home systems require a different treatment. The technical solution is the SHS itself, and PayGo (pay-as-you-go, in which the household pays in small, frequent installments, typically by mobile money) can be the enabling technology used to meter service, collect payments, and manage disconnection or reconnection remotely. But PayGo should not be confused with the business model. In many existing schemes, PayGo is used to finance the sale or rent-to-own acquisition of a kit: the household pays in installments and eventually owns the asset. That may help overcome the upfront affordability barrier, but it does not create a permanent service obligation. Once the warranty, repayment period, or limited-service contract ends, the household remains responsible for battery replacement, repairs, and future upgrades.

The model proposed here is different: energy-as-a-service. The provider remains responsible for keeping the system operational over time, while the customer pays a regulated service fee for a defined level of electricity service. The public side should define the service tier, availability standard, maintenance response time, replacement obligation, customer-service requirements, data-reporting duties, consumer-protection rules, and permitted disconnection or suspension procedures. PayGo can still be used to collect the service fee or manage arrears, but it remains an enabling technology within the service model, not the model itself.

This distinction matters financially. In an SHS asset-sale model, the provider's risks are mainly sales volume, working capital, customer credit, and payment collection. In an energy-as-a-service model, the provider must finance and maintain a portfolio of assets over time. Its bankability therefore depends on the regulated service fee, the subsidy payment, contract duration, payment security, performance rules, and termination compensation. The subsidy should not be treated as a one-off affordability grant for a product. It should be the payment required to make a defined service obligation viable at the regulated customer fee.

A concession model can also be used for SHS, and it would award a service obligation over a defined geography, customer group, or service tier. The concessionaire would be required to install, maintain, repair, and replace systems of a stipulated capacity, provide local customer support, meet performance standards, and report service data. Customers would pay a regulated service fee set at an affordable level. The difference between that fee and the efficient cost of providing the service would be met through an explicit subsidy. As with mini-grids, the tender can reveal the initial subsidy requirement or allowed remuneration, and the regulator can subsequently administer the service obligation under pre-defined adjustment and performance rules.

Existing mini-grid operators, solar-kit vendors, and PayGo providers should be handled through a transition regime. They should be mapped, audited, and classified according to whether they can migrate into the regulated service-obligation framework, require remediation, or should be bought out or phased out. Existing customer rights, asset valuation, service standards, and tariff treatment should be addressed explicitly. Otherwise, the new regime will create unequal treatment between customers receiving a regulated affordable service and customers left under legacy arrangements.

Under this approach, decentralized supply is not a residual project category. Mini-grids become regulated local service concessions. Solar home systems become energy-as-a-service obligations where they are intended to support permanent universal access. In both cases, the regulatory discipline is the same: a defined service standard, an affordable customer charge, an explicit subsidy for the gap, credible payment security, and a financed obligation to maintain and replace assets over time. The objective is not to install equipment. It is to ensure that electricity service continues.

3.5. Finance-Co as a financial intermediary

The architecture's final component is financial. An integrated plan needs a single, strong focal point that converts dispersed public support, concessional resources, tariff-backed surpluses, and commercial capital into a predictable financing structure for a multi-technology program. This paper names that focal point **Finance-Co** and stresses that it is best understood as a*n institutional role* rather than a particular legal entity. Finance-Co is a government-affiliated financial intermediary dedicated to the distribution sector and universal access; it does not operate assets or procure works. It performs four defining roles. It **pools** inflows—government equity and guarantees, donor grants, concessional loans, commercial debt, and the operating surpluses that flow upstream from the grid operator—into a single platform. It **ring-fences** those flows in dedicated accounts so that they are insulated from the general budget and from the incumbent utility's balance sheet. It provides **payment security**, hardening the settlement of subsidies and cross-subsidy transfers through standardized rules, escrow or reserve accounts, and payment waterfalls, so that operators and their lenders can rely on being paid for verified service. And it makes cross-subsidization **explicit and auditable**, routing regulated tariff revenues from higher-consuming and higher-income segments into the pool and reallocating them transparently to fund off-grid support and high-cost connections.

Figure 1 presents the economic flows that Finance-Co coordinates: government and development partners channel equity, guarantees, grants, and concessional loans into the vehicle; the vehicle funds investments in new assets through the incumbent or a concessionaire, provides subsidies that close viability gaps for mini-grid and stand-alone providers, and receives both regulated tariff revenues and the grid operator's surplus, with a dedicated channel routing cross-subsidies among customer classes.

Fig. 1 Finance-Co in an integrated financing approach for on-grid and off-grid distribution

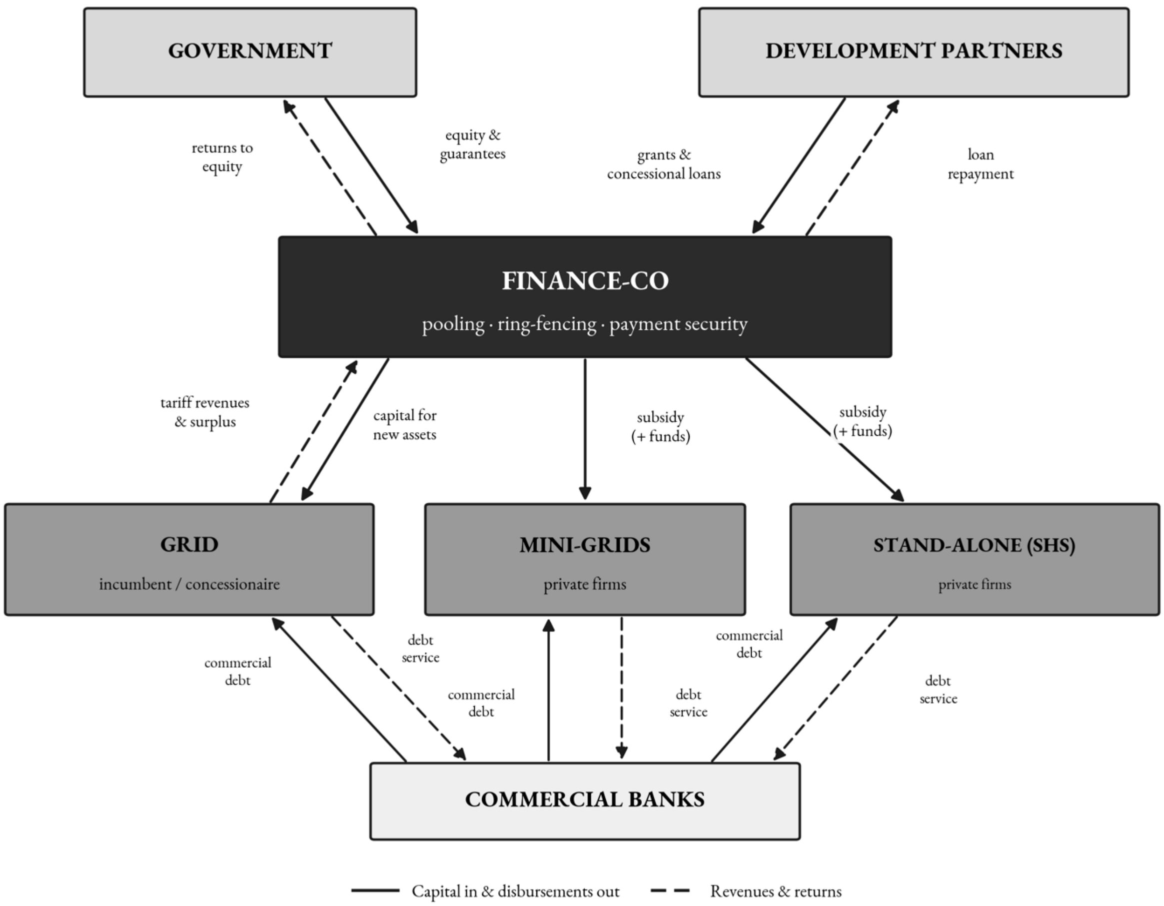

Fig. 1 Finance-Co in an integrated financing approach for on-grid and off-grid distribution. Original elaboration based on the integrated-financing framework (Díaz-Pastor et al., 2026a, 2026b; Díaz-Pastor and Pérez-Arriaga, 2025).

Figure 2 illustrates the separation of the two gaps over a stylized rollout: total cash expenditure peaks early with front-loaded investment, the cost of service rises and remains elevated as the asset base accumulates, and realized revenues lag because new customers consume little and tariffs are constrained by affordability—so that the wedge between the cost-of-service curve and the revenue curve is the viability gap, while the wedge between total expenditure and the cost of service is the financing needs. The consolidation enforced by Finance-Co is what allows both wedges to be funded, by the right instrument, without confusing one for the other.

Fig. 2 The two gaps that bind implementation, over a stylized rollout

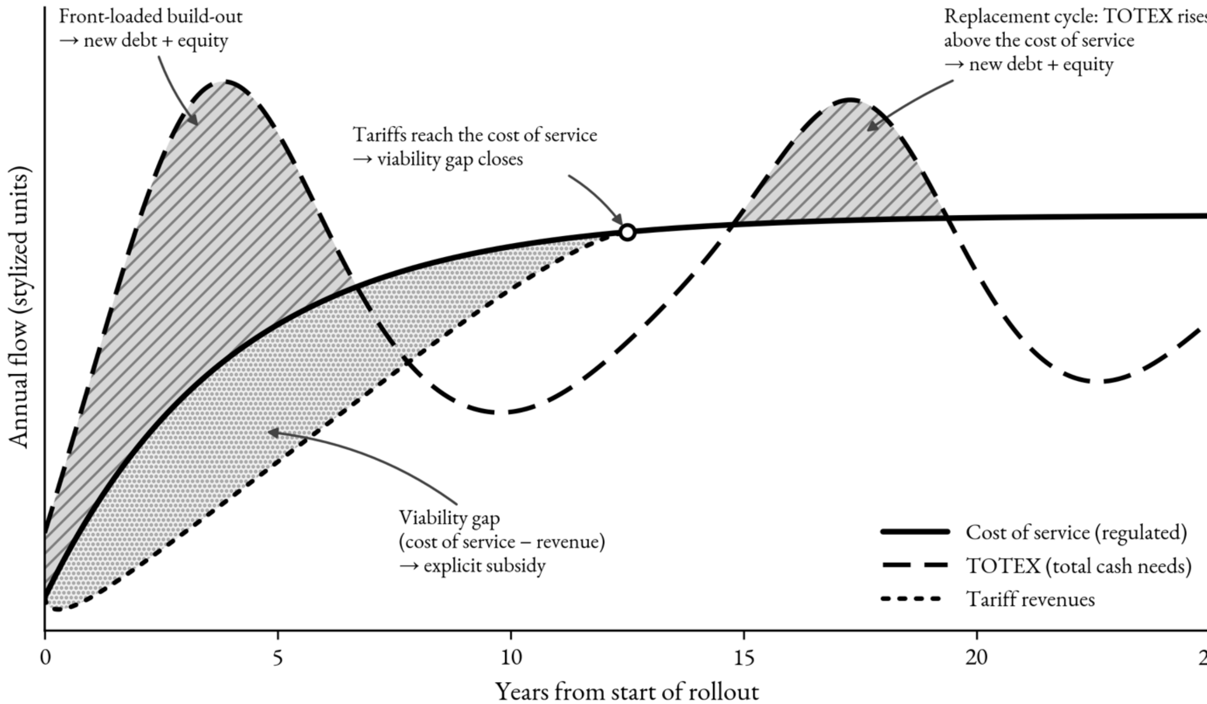

Fig. 2 The two gaps that bind implementation, over a stylized rollout: the financing needs (TOTEX − CoS) and the viability gap (CoS − REV). Original elaboration based on the integrated-financing framework from (Díaz-Pastor et al., 2026a, 2026b; Díaz-Pastor and Pérez-Arriaga, 2025).

International precedent supports the feasibility of this financing role across very different legal forms: Bangladesh's IDCOL, Tanzania's Rural Energy Fund, and Spain's Electricity Deficit Amortization Fund all centralized financial management to stabilize flows and crowd in capital (Cabraal et al., 2021; Danielsson and Zhou, 2011; IEA, 2021). None implies a one-size-fits-all institution. They support a robust institutional-design proposition: when mandates, governance, and accountability are clear, centralizing financial management reduces discretion and volatility in subsidy flows, improving bankability and lowering the effective cost of capital. The applications that follow show the same financing role taking three different institutional shapes—an upgraded credit vehicle in Uganda, a Ministry of Finance-anchored settlement structure in Zambia, and, in Madagascar, the same integrated financial analysis carried out region by region rather than through a single national vehicle—while performing the same four roles.

4. Uganda: A fully worked reference case

Uganda provides the clearest context in which to define the full proposed architecture, as an institutional transition raised the question of "what comes next". This section applies the framework from start to finish, drawing on the computational model and results of (Díaz-Pastor and Pérez-

Arriaga, 2025) and the original project developed in collaboration with the European Union (Pérez-Arriaga et al., 2022).

4.1. The institutional starting point: After the Umeme concession

Uganda's distribution segment passed through a full reform cycle in a single generation. The vertically integrated utility was unbundled in 1999, and in 2005 a twenty-year distribution concession was granted to Umeme Ltd. Over the life of that franchise the results were substantial: technical and commercial losses fell from almost 38 percent to 16.2 percent, the customer base grew roughly nine-fold, and collection efficiency approached 99 percent (Twesigye, 2023; Umeme Limited, 2025). Yet consumers continued to question tariff levels, and the concession's financing structure came to be seen as a source of intermediation cost. When the concession expired on 31 March 2025, the buy-out of the unrecovered regulated asset base crystallized the fiscal and regulatory stakes: Umeme claimed USD 234 million, the Auditor-General approved only USD 118 million, the government secured a USD 190 million facility to cover the admitted portion, and London-seated arbitration was triggered for the balance (Elias Biryabarema, 2025; Njuguna, 2025). The episode is a textbook illustration of the hold-up problems and contingent liabilities that unbundled regimes were meant to mitigate, and it set the terms of the design problem: how to retain the efficiency gains of private operation while restoring transparent cost recovery and credible financing for a far larger rollout.

4.2. Two entities: Service-Co and Finance-Co

The proposed post-concession architecture is built around two interconnected entities that instantiate the functions of Section 3. **Service-Co** is a regulated, privately operated distribution service company, competitively selected and granted a twenty-year concession by the regulator to operate the publicly owned national distribution network. It carries the universal service obligation and is responsible for operation, maintenance, metering, billing, collection, network densification, and downstream engineering-procurement-construction, and it submits investment and operating proposals for regulatory clearance and cost recovery. Critically, all capital expenditure is financed by the financing vehicle and remains on the public balance sheet, so that Service-Co's own revenue requirement covers operating expenditure while its operational surplus flows upstream. **Finance-Co**, the second entity, performs the pooling and settlement function: it aggregates government equity and guarantees, donor grants, concessional debt, and the tariff-backed surpluses transferred from Service-Co, and it allocates these resources to grid and off-grid investments under transparent rules. In Uganda the function could be discharged by upgrading an existing *Uganda Energy Credit Capitalisation Company* (UECCC) rather than creating a new institution—an administrative simplification that limits the number of implementing bodies (Díaz-Pastor and Pérez-Arriaga, 2025).

4.3. The least-cost pathway

The quantitative baseline is Uganda's National Electrification Strategy, which requires approximately USD 4.7 billion of investment to deliver about 10.4 million new connections through grid extension, mini-grids, and stand-alone systems (MEMD and World Bank, 2022). The technology mix illustrates why integrated planning matters. Of the currently unserved population, the most cost-effective allocation serves about 53 percent through Tier-1 stand-alone solar systems—owing chiefly to their remote, dispersed distribution—about 45 percent through grid extension and densification, and only about 2 percent through mini-grids. Because unit costs differ sharply across modes, the shares of investment diverge markedly from the shares of connections: grid extension absorbs roughly 83 percent of investment, stand-alone systems about 9 percent, and mini-grids about 8 percent. A plan that read connection shares as investment shares—or that assumed a single cost of capital across the three modes—would misallocate both capital and technology.

4.4. The cliff: 2030 versus 2040

The framework's most consequential finding concerns the pace of the rollout. Reaching universal access by 2030 concentrates the rollout into a few years and produces an investment cliff: average annual distribution capital expenditure over 2026–2030 reaches USD 809.8 million, a level that exceeds Uganda's historical capacity to execute and absorb. Extending the horizon to 2040, holding all regulatory, tariff, and industrialization policies constant, redistributes the same total investment over a longer period and smooths that cliff. The effects are large and move together, as summarized in Table 1. Average annual distribution capital expenditure for 2026–2030 falls by about two-thirds, from USD 809.8 million to USD 269.9 million. On-grid commitments fall from USD 3.4 billion to USD 1.1 billion and off-grid from USD 0.7 billion to USD 0.2 billion over the same window. The funding that Finance-Co must mobilize falls from about USD 3.0 billion to about USD 0.7 billion, required grants from USD 600 million to USD 200 million, and concessional debt from USD 2.0 billion to USD 370 million. Paradoxically, the smaller program delivers stronger early returns: with equity contributions front-loaded while tariff transfers scale rapidly, Finance-Co's equity internal rate of return rises and the debt service coverage ratio strengthens, and off-grid developers' early-period equity returns approach 30 percent by 2031 even as per-connection subsidies decline. Easing the financing need does not weaken the investment case; it improves it.

Table 1 Uganda: key comparative results, 2030 base case versus the 2040 target.

Metric	Base case (100% in 2030)	2040 target	Δ
Average annual distribution CAPEX, 2026–30	USD 809.8 m	USD 269.9 m	−66.7%
On-grid CAPEX, 2026–30	USD 3.4 bn	USD 1.1 bn	−66.7%
Off-grid CAPEX, 2026–30	USD 0.7 bn	USD 0.2 bn	−66.7%
Finance-Co funding need, 2026–30	USD 3.0 bn	USD 0.7 bn	−77.7%
Required grants, 2026–30	USD 600 m	USD 200 m	−66.7%
Concessional debt, 2026–30	USD 2.0 bn	USD 370 m	−81.5%
Finance-Co equity IRR (2031)	17.7%	65.6%	↑
Off-grid equity IRR (2031)	20.7%	29.5%	↑

Source: (Díaz-Pastor and Pérez-Arriaga, 2025)*, their Table 4. Same total investment redistributed over a longer horizon.*

4.5. Convergence to self-sustainability

The financing structure is catalytic rather than permanent. In the early years, government equity acts as a first-loss tranche that unlocks grant financing, after which concessional debt is mobilized as regulated tariff revenues begin to provide debt-service capacity; from 2030 onward, the system relies increasingly on internal cash flows. The trajectory of the grid operator illustrates the convergence. Regulated tariff income for Umeme and, after 2025, Service-Co rises from USD 590.9 million in 2026 to USD 1.73 billion in 2030 and USD 6.80 billion by 2040, while the surplus transferred from Service-Co to Finance-Co rises from USD 54.5 million in 2026 to USD 502.7 million in 2030 and USD 3.57 billion by 2040. By 2040, regulated tariffs are sufficient to cover the full revenue requirement of the distribution segment—grid and off-grid alike—and the concessional debt has been fully amortized. From that point the system requires no further external support: it has become, in the framework's terms, self-sustaining by design.

4.6. Lessons

Three lessons generalize beyond Uganda. First, financial viability is not the same as implementation credibility. Both the 2030 and 2040 horizons can be made financially viable in the model, but the 2030 target requires an exceptional front-loading of concessional finance, procurement capacity, and institutional execution. A credible access target must therefore be calibrated not only to the least-cost plan, but also to the country's ability to absorb funds, contract works, supervise delivery, and settle subsidies on time. In this sense, aligning ambition with domestic absorption capacity is more credible than assuming an extreme short-term increase in grants.

Second, consolidating financing and subsidy flows inside one vehicle can improve bankability, but only if the vehicle is rule-based. Its value is not that it generates private returns mechanically. It reduces transaction costs, aggregates demand, standardizes contractual conditions, lowers perceived payment risk, and gives operators a predictable settlement counterparty. This matters especially for mini-grid and stand-alone service providers, whose economics depend less on one-off CAPEX support than on the credibility of recurring payments for service continuity, maintenance, and asset replacement. Under these conditions, private capital can be crowded in because the service obligation becomes financeable, not because the underlying rural demand is sufficient on its own.

Third, incentive alignment is central. Equity returns should be earned only when service obligations are met. Access to surpluses should be suspended when covenants are breached. Performance failures should trigger predefined penalties, not ad hoc renegotiation. The purpose of centralization is therefore not to remove regulation, but to make regulation more credible: fewer project-by-project exceptions, clearer payment rules, and a more transparent link between performance, remuneration, and risk allocation. Efficient operators can earn stable returns; inefficient operators face predictable consequences. This is the core regulatory lesson of the Ugandan case, and it is consistent with the broader logic of incentive-based regulation and credible commitment (Joskow, 2024). The Ugandan case illustrates the architecture when the binding constraint is coordination and financial credibility; the next case shows how the framework changes when the binding constraint is different.

5. Zambia: The same architecture, recalibrated

Zambia applies the same logic to a different starting point, and the contrast is informative precisely because so many factors are held constant. The design problem in Uganda was defined by an expiring concession, whereas in Zambia it is defined by a newly issued least-cost plan, a distressed national utility, and a thin domestic revenue base. This section is based on the Rural Electrification Master Plan (REMP) and the associated regulatory and financial analysis developed by the African School of Regulation in collaboration with Sustainable Energy for All.

5.1. The REMP as starting point—and the missing layer

In April 2026 the government launched an updated Rural Electrification Master Plan (REMP) for 2025–2030 (MoE and REA, 2026). It is the right techno-economic starting point: a least-cost allocation requiring roughly USD 1.52 billion of investment to deliver about 2.5 million connections or systems by 2030—739,560 grid connections (USD 621.8 million), 328,304 mini-grid connections (USD 610.1 million), and 1,440,007 stand-alone solar systems (USD 288.0 million). It should not, however, be mistaken for a complete bankable implementation plan. The missing layer is exactly the one the framework supplies: the REMP must be converted from a least-cost allocation of modes into a set of long-term public service obligations that can be tendered, regulated, financed, and monitored over the useful life of the assets and beyond. The central challenge is not to connect households once but to guarantee permanent service—maintenance, replacement, capacity expansion, customer care, and affordability—so that connections do not become stranded assets. The investment figure sizes the initial delivery program; it does not yet settle the cost-of-service, subsidy, liquidity, or payment-security architecture.

5.2. The delivery split

The architecture is implemented across four vehicles, chosen so that the binding constraint—ZESCO's distressed balance sheet—is addressed directly. New grid extensions are delivered 60 percent by **ZESCO**, the national utility, and 40 percent by **PrivateCo**, a private on-grid concessionaire; mini-grids and stand-alone systems sit entirely within an **Off-grid SPV**; and the pooling and settlement function is performed by a **Finance-Co**, anchored in the Ministry of Finance. The rationale for this split follows directly from that constraint. Because its distressed balance sheet leaves ZESCO effectively unable to raise commercial capital, the portion of the rollout assigned to it must be funded almost entirely by grant rather than by debt or equity it could not service—hence the 90 percent grant on ZESCO's share. PrivateCo is introduced to supply the capital ZESCO cannot: a private on-grid concessionaire that commits real capital against a regulated return, which is why only 20 percent of its rollout is granted and why it is remunerated at the higher, private cost of capital. Its financing structure is developed further below.

Two features of the design account for the results. The cost of capital that each operator's remuneration reflects differs by vehicle: ZESCO's blended rate is about 5 percent, while the private and off-grid operators are remunerated at about 9 percent, the returns agreed with stakeholders. And the share of rollout investment covered upfront by a grant is set at 90 percent for ZESCO, 20 percent for PrivateCo, and 50 percent for the off-grid technologies. Together these explain why ZESCO's rural block ends with the smallest lifetime viability gap of the metered channels (USD 341 million)—because 90 percent of its rollout is granted, little capital enters its rate base—while PrivateCo, which keeps genuine capital at risk, carries a lifetime gap (USD 957 million) that is, in substance, the multi-year remuneration of that capital: the same service at the same tariff, recovered on a different payment profile. The arrangement is anchored in Zambia's own statute: the Public-Private Partnership Act No. 18 of 2023 and its 2024 Regulations provide the contractual basis, while Statutory Instrument No. 52 of 2024 governs smaller distributed systems (Government of the Republic of Zambia, 2024, 2023a).

5.3. The 3 percent levy as cross-subsidy and exit engine

The financial centerpiece is a domestic cross-subsidy that doubles as an exit strategy. A 3 percent Rural Electrification Levy on electricity bills routes contributions from existing consumers—predominantly mining and urban customers, whose demand grows with an industrializing economy—into Finance-Co, where it funds the recurring viability gap of the rural program (Government of the Republic of Zambia, 2023b).

The levy's significance is that it grows with the wider sector regardless of the rural rollout, so the program's exit financing is the growth of the electricity sector itself. The order in which Finance-Co applies its sources is itself the burden-sharing policy, and it is fixed: the levy is applied first, so consumers contribute before anyone else; donor grants then cover 50 percent of whatever gap remains, matching the domestic effort rather than carrying the program; concessional debt from development finance institutions covers what a 1.25× coverage test on Finance-Co's own cash flows permits—meaning the loan is sized so that each year's cash flow is at least 1.25 times the repayments due that year (interest plus principal), a 25 percent safety margin—which prudence limits to USD 337 million against a USD 1,270 million financing requirement; and government equity covers the residual, last in the order, not first.

The architecture has three headline results. The request to donors is about **USD 1,096 million**—USD 851 million of capital grants on the USD 1.52 billion investment plus USD 245 million toward the rural operating shortfall in the early years. Donor support ends: grants peak at USD 383 million in the final rollout year of the REMP and fall to approximately zero from **2037**, the year tariff revenues reach the full cost of service of the system, and the levy becomes sufficient to fund the residual gap. And every donor grant dollar arrives with roughly one dollar of private and commercial capital—about USD 1,066 million in total, a leverage of approximately one to one.

5.4. ZESCO's inherited financial burden: Outside REMP's program

Zambia adds a complication that Uganda does not present: ZESCO enters the program with a large financial burden accumulated before the rural electrification strategy begins. This burden is not ignored. It is modeled explicitly in ZESCO's projected financial statements and affects the utility's cash flows, leverage, liquidity, and debt-service capacity. But it is kept separate from the rural access program because it does not correspond to new investment in electrification and does not represent a subsidy required to make rural service affordable.

The distinction is essential. ZESCO's unpaid invoices to electricity suppliers, estimated at about USD 2,245 million, correspond to electricity already supplied. Its pre-existing debt stock, estimated at about USD 3,524 million in 2025, is also unrelated to the new rural rollout. Neither item represents CAPEX required to connect new customers. Neither is part of the viability gap created by charging affordable rural tariffs below the efficient cost of service. These are inherited sector obligations, and they must be paid through a separate restructuring path.

The model therefore treats the unpaid supplier invoices as a refinancing operation. The short-term payment obligations are converted into a long-term concessional facility. Suppliers are paid, and ZESCO repays the new facility gradually over time. The drawdowns, interest payments, and principal repayments are included in ZESCO's projected accounts as real financial obligations borne by the utility. The pre-existing debt stock is also retained in ZESCO's balance-sheet trajectory and debt-service profile. These amounts therefore remain visible in the model and affect ZESCO's financial recovery.

At the same time, these inherited obligations are kept outside the rural access aggregates. Grants, viability-gap subsidies, and Finance-Co resources are not used to settle past supplier invoices or refinance ZESCO's existing debt stock. They are used to finance the access program: new investments, affordable service, and the regulated subsidy required to close the gap between customer payments and efficient service costs. This separation prevents the access program from being charged with obligations that were already present before it began.

This distinction also explains why the REMP has a limited incremental impact on ZESCO's financial statements. The reason is not that the rural program has no cost. It is that ZESCO's projected accounts are already dominated by the inherited burden: supplier-payment refinancing, pre-existing debt, and the associated repayment obligations. Against that background, the additional effect of the REMP on ZESCO is comparatively small, especially where the program is structured so that rural investment and viability-gap payments are channeled through Finance-Co rather than loaded directly onto ZESCO's balance sheet.

The accounting discipline is therefore central to the interpretation of the results. Combining ZESCO's inherited financial burden with the rural electrification program would inflate the apparent cost of universal access and make donors appear responsible for past sector deficits. Excluding it from the rural program aggregates does not mean excluding it from the financial analysis. The correct treatment is to model it in ZESCO's accounts, report it as a separate implementation risk, and keep it outside the investment, subsidy, donor-request, and Finance-Co aggregates of the rural access program.

5.5. The same trade-off regarding timing, stated frankly

Zambia confronts the same question of timing, and reporting it transparently is part of the methodology. A 2040 target rather than 2030 softens every fiscal peak: the largest donor-grant year falls from USD 383 million to USD 224 million, the largest investment year from USD 442 million to USD 211 million, and total sovereign equity falls by almost half, by about USD 675 million, as the financing mix shifts from grants and equity toward the levy and concessional debt. But this fiscal smoothing is not costless. It changes three things at once: when access is delivered, whether the private concession remains bankable, and which replacement costs are visible within the 2050 horizon.

First, the 2040 target does not reduce the access need; it delays when households and communities receive service. Within the 2050 model horizon, the slower rollout reaches about 2.3 million fewer people than the 2030 path, 14.6 million rather than 16.9 million. The fiscal smoothing therefore comes with a measurable access cost.

Second, the delay changes the bankability and financial structure of the private grid concession. PrivateCo still has to finance the network expansion, but the revenue base builds over sixteen years rather than five. This weaker cash-flow ramp reduces the debt that can be supported under the coverage test, which admits less than half the borrowing assumed in the faster rollout. The financing gap is then filled with sponsor equity. This increases the sponsor's capital exposure while pushing recoveries further into the future. On the current terms, PrivateCo's equity internal rate of return falls from 11.7 percent to 9.7 percent, below the 12 percent requirement. The relevant conclusion is not simply that the concession needs a higher tariff or subsidy. Rather, the slower rollout changes the financeable capital structure itself: the debt-sizing constraint allows materially less leverage, increases the equity share, and therefore implies a different weighted average cost of capital. The 2040 scenario should therefore be evaluated with the capital structure that is actually bankable under its slower cash-flow profile, and with the corresponding WACC, instead of applying the same financing assumptions used for the faster 2030 rollout.

Third, the lower investment total is partly an artefact of the comparison horizon. In the 2030 case, earlier rollout cohorts reach maintenance and replacement milestones before 2050. In the 2040 case, many of those same costs fall after 2050 and therefore disappear from the reported lifetime total. The apparent saving is therefore mostly a deferral of obligations beyond the observation window, not a structural reduction in the economic cost of electrification. The 2040 scenario should be read as a fiscal-smoothing strategy with delayed access and weaker private-sector bankability, not as a cheaper version of the same program.

The Zambian case carries one overriding methodological lesson, which is a fundamental rule for any application: do not mix the layers. Five figures recur and must never be conflated (see Table 2)—the REMP investment of USD 1.52 billion; the lifetime program capital expenditure of about USD 3.31 billion once maintenance and replacement are included; the donor request of about USD 1.10 billion; the net sector viability-gap disbursements of about USD 4.77 billion, funded mostly by the levy over twenty-five years; and Finance-Co's total lifetime sources and uses of about USD 6.16 billion. Each measures a different thing, funded by a different party, over a different horizon. Quoting any one of them as if it was the donor request would distort every decision that follows.

Table 2 Zambia: the five layers that must not be conflated.

Layer	USD bn	What it measures — and who funds it
REMP investment	1.52	CAPEX of the rollout; the plan's reference figure
Lifetime program CAPEX	3.31	Rollout + maintenance + replacement to 2050
Donor request	1.10	Grants requested (0.85 capital + 0.25 rural viability gap)
Net sector viability-gap disbursements	4.77	All viability-gap support paid, mostly levy-funded
Finance-Co lifetime sources = uses	6.16	The full fiscal flow assembled and disbursed

Source: (MoE and REA, 2026) and REMP financial model developed by the authors, base case. Each figure measures a different thing, funded by a different party, over a different horizon.

6. Madagascar: The framework taken up at national scale

Madagascar completes the demonstration by showing the architecture not as a proposal but as an analysis that a lead development partner—GIZ, with the European Union and the French development agency—has adopted as its working method and is applying across the country, at the most difficult starting point of the three. This section draws on the country's electricity code and recovery program, on the *Cadre d'Électrification Rurale Intégrée*, and on two district projects being prepared under it.

6.1. The hardest starting point

Madagascar has one of the lowest access rates in Africa. Around 36 percent of the population has electricity—rural access far lower—and roughly 19 million people remain without it, overwhelmingly in the countryside (GIZ, 2025a). The national utility, JIRAMA, holds a monopoly on transmission and distribution in urban areas while generation may be entrusted to private actors; it is financially distressed, with technical and commercial losses reduced from about 35 percent toward 25 percent but still high, arrears to its electricity suppliers of roughly MGA 2.4–2.6 trillion at the end of 2022, and government transfers averaging about 1.2 percent of GDP over 2019–2024. A JIRAMA recovery plan for 2025–2028, supported by the International Monetary Fund and the World Bank, aims to restore viability and phase out those subsidies (IMF, 2025). Crucially, the national backbone is thin.

The interconnected transmission system amounts to only about 400 km of high-voltage lines serving the three main urban systems; isolated centers account for roughly a fifth of consumption; and upstream generation is tight enough to produce recurrent shortages. The grid that exists does not, in practice, reach most of the territory still to be electrified. Yet Madagascar is also a world leader in decentralized electrification: more than 300 decentralized systems are already operational—JIRAMA's isolated grids and mini-grids run by independent operators—and, counting nano-grids and solar kits, hundreds of thousands of systems are in service, with rural electrification entrusted by law to a dedicated agency (GIZ, 2025c). The national ambition was fixed in January 2025, when the Government signed a National Energy Compact with the World Bank, the African Development Bank, and other partners under the Mission 300 initiative, targeting 80 percent access by 2030, a doubling of renewable capacity, and roughly USD 7 billion of investment, more than half of it expected from the private sector (GIZ, 2025a).

6.2. An integrated planning framework, but not yet a full financing architecture

Madagascar is distinctive because the integrated approach is not introduced here as a theoretical proposal. It is already being applied as a working method for rural electrification. The Integrated Framework for Electrification—developed at MIT and Comillas University for the Global Commission to End Energy Poverty, and now championed by the African School of Regulation—

has been adapted in Madagascar as the *Cadre d'Électrification Rurale Intégrée* (CERI). In its Malagasy form, CERI is a territorial, multi-technology planning approach: it combines grid extension, mini-grids, nano-grids, and stand-alone systems, drawing on available solar and hydro resources, into a single district-level electrification plan and financial model in order to reach universal access at an affordable cost (GIZ, 2025a).

This is an important step. It moves rural electrification away from isolated projects and toward an integrated territorial plan. It also creates the basis for comparing technologies on a consistent least-cost and service-quality basis, instead of treating grid extension, mini-grids, and stand-alone systems as separate donor windows. The GIZ-supported rural electrification work in Madagascar illustrates this approach in practice: long-term plans combine grid connections, solar mini-grids and nano-grids across defined localities, with investment and connection requirements assessed as part of a single plan. The European Union's Global Gateway also identifies rural mini-grids in the South and West of Madagascar as a focus of renewable-energy support.

The operational vehicle for this approach is *Tosika Angovo*, or TANGO, supported by GIZ and development partners. Its relevance for this paper is not only that it mobilizes finance, but that it addresses the two constraints that repeatedly determine whether rural electrification plans become real investments: bankability and absorption capacity. More public and private finance is necessary, but insufficient. The sector also needs the capacity to prepare bankable projects, procure them, supervise delivery, and convert committed funding into operating assets on the ground. This is why Madagascar is a useful case: it shows that integrated planning is necessary, but not by itself enough.

The institutional and legal basis is also more developed than in many comparable settings. The Electricity Code, Law No. 2017-020, sets the sector framework for electricity activities, including the legal regimes for generation, transmission, distribution and supply, and reconstitutes the regulator. *Agence de Développement de l'Électrification Rurale* (ADER) remains the rural electrification agency, while the reform of the National Electricity Fund through Law No. 2017-021 creates the public funding channel for rural and peri-urban electrification and related support instruments (Government of Madagascar, 2017a, 2017b). In legal form, therefore, Madagascar already has the main building blocks: a sector code, a regulator, a rural electrification agency, and a dedicated fund.

But this is precisely where the remaining gap becomes clear. A planning framework and a capital-subsidy fund do not yet amount to a full financing architecture. The missing function is the one emphasized throughout this paper: a credible mechanism for recurring payments, service-continuity obligations and payment security over the life of the assets. Rural electrification assets must not only be built. They must be operated, maintained, expanded and replaced. A fund designed mainly to channel capital support can reduce upfront costs, but it does not automatically provide the long-term settlement mechanism required to make regulated service obligations bankable.

Madagascar therefore demonstrates both progress and incompleteness. CERI provides integrated territorial planning discipline. TANGO helps translate that planning into transaction preparation and financing mobilization. The legal framework provides institutional entry points through the regulator, ADER and the electricity fund. What still must be supplied is the financial layer that converts these elements into a durable service model: explicit subsidy commitments, predictable disbursement rules, payment security, and remuneration linked to defined service obligations. The lesson is not that Madagascar lacks the architecture altogether. It is that the planning architecture is already emerging, while the long-term financing and settlement architecture still must be completed.

6.3. Two examples of district projects under the CERI

The framework's reality is clearest in the projects being prepared under it, each a single district plan spanning all three delivery modes. The first, in the central district of **Fandriana** (Amoron'i Mania region), is led by the operator HIER and covers 183 fokontany across nine communes, about 164,000 people. Its CERI plan reaches 83 localities—76 connected to the grid and 7 pre-electrified by solar nano-grids—serving 17,714 users by year 30 through some 234 km of medium- and low-voltage network and 2.75 MW of hydro and solar capacity: the rehabilitated Ankerivato run-of-river plant, a new 2 MW / 12 MWh solar plant built in stages, with a 5 MW hydro plant at Maromanana as an alternative source. The thirty-year cost is about EUR 17.6 million, of which roughly EUR 4.1 million—about 23 percent—is private investment and EUR 13.5 million is subsidy, delivered in two phases: northern extension and densification first, then seven communes to the south (GIZ, 2025b).

The second project, **Jiro Taratra** (Bongolava region, Tsiroanomandidy district), is led by Africa GreenTec and CASIELEC under the rural-electrification agency's first competitive call and covers 81 fokontany across twelve communes, about 170,000 people. Its plan reaches 94 localities—65 by grid, 4 by solar mini-grid, and 25 by nano-grid—serving 63,240 customers by year 33 through about 531 km of network and 9.14 MW of solar capacity, with seventeen initially stand-alone mini-grid plants designed to be progressively interconnected into the growing grid as the project matures. The cost is about EUR 52.6 million, of which roughly EUR 23.3 million—about 44 percent—is private and EUR 29.3 million is subsidy, phased over the project's life: an off-grid quick start, a medium-term grid build to Ankadinondry Sakay, and a long-term extension north to Tsiroanomandidy (GIZ, 2025c). Table 3 sets the two side by side.

Table 3 Madagascar: two district projects under the CERI.

Indicator	Fandriana (HIER)	Jiro Taratra (AGT + CASIELEC)
Region / district	Amoron'i Mania	Bongolava / Tsiroanomandidy
Coverage	183 fokontany, 9 communes; ~164,000 people	81 fokontany, 12 communes; ~170,000 people
Localities (grid / mini-grid / nano-grid)	83 (76 / 0 / 7)	94 (65 / 4 / 25)
Customers by target year	17,714 by year 30	63,240 by year 33
Distribution network	~234 km	~531 km
Renewable capacity	2.75 MW (hydro + solar)	9.14 MW (solar)
Total investment	~EUR 17.6 m	~EUR 52.6 m
— of which private	~EUR 4.1 m (~23%)	~EUR 23.3 m (~44%)
— of which subsidy	~EUR 13.5 m	~EUR 29.3 m

Source: (GIZ, 2025c, 2025b). One district plan per project, co-planning generation and multi-technology distribution.

6.4. Planning when the national grid is not the anchor

Madagascar contributes a third and distinct binding constraint. The Ugandan case turns on coordination, concession transition, and the need to make an integrated financing vehicle credible. The Zambian case adds the problem of a utility entering the program with a large inherited financial burden that must be modeled but kept separate from the access program. Madagascar is different. Its constraint is structural: very low access, extreme geographic dispersion, a fragmented legacy of decentralized systems developed under earlier business models, a rural electrification fund that does not by itself provide a bankable life-cycle financing mechanism, and a national grid that is too sparse to serve as the default platform for universal access.

That last feature changes the planning problem. Where the transmission backbone is thin and upstream supply is constrained, generation and distribution cannot be planned as separate layers. The relevant planning unit becomes the district or subregional supply system: a local configuration of generation, storage, distribution and customer connections designed together. In that setting, mini-grids, nano-grids, stand-alone systems and selective grid extension are not competing project categories. They are components of one territorial electrification plan.

This is the role of the CERI approach in Madagascar. Each CERI project starts from a defined territory, and co-plans supply and distribution within it. Local generation—including rehabilitated hydro where available and new solar capacity where appropriate—is combined with grid, mini-grid, and nano-grid distribution solutions. Instead of waiting for the national grid to arrive, the plan can create a local backbone by progressively interconnecting initially separate decentralized systems. The direction of integration is therefore different from a conventional grid-extension model: the system is built outward from district-level supply structures, with later interconnection where it becomes technically and economically justified.

This has a direct regulatory implication. If decentralized systems are expected to become part of a future interconnected system, investors need rules before they invest. The framework must specify what happens when the main grid reaches an area already served by a mini-grid or local network: whether the assets are integrated, transferred, compensated, or operated under a distribution concession. The compensation rule should be based on unrecovered regulated value or another defined contractual measure, not negotiated after the event. These provisions are not secondary. They reduce stranded-asset risk, lower the required return, and make decentralized investment financeable.

The two CERI projects therefore illustrate the architecture being operationalized under difficult conditions. They combine supply and distribution in one district-level plan; they mobilize private capital at meaningful shares of total cost, about 23 percent and 44 percent in the two project packages considered; and they phase delivery in line with what the sector can prepare, finance, procure and supervise. The point is not only that private capital is present. It is that private capital is being asked to finance a defined service package within an integrated plan, rather than isolated assets with uncertain future treatment.

TANGO's portfolio ambition points toward the scale-up challenge: seven CERI projects, about 16 MW of renewable capacity, 160,000 users and roughly EUR 240 million investment. That is still a program under construction, not yet proof of full national delivery. But it shows the relevant institutional direction. Madagascar is not starting from a blank page: the integrated planning method has been adopted, transaction preparation is being organized around it, and the financing question is being framed at portfolio level rather than project by project.

Madagascar therefore sharpens the argument from the hardest starting point. Where the national grid is not a sufficient anchor, universal access must be planned through territorial supply systems that combine technologies, define service obligations, protect investors against future grid-arrival risk, and secure life-cycle financing. The lesson is not that decentralized supply is a temporary substitute until the grid arrives. In Madagascar, decentralized and local systems are part of the core architecture of electrification. The remaining task is to complete the financing and settlement layer that makes those systems durable, affordable and bankable over the life of the assets.

7. The same architecture, a different recipe

Placing the three applications side by side reveals what the framework holds fixed and what it tunes—and the distinction is the framework's principal claim to generality.

7.1. What is invariant?

Five elements appear unchanged across all three applications, and they constitute the framework proper. The first is a binding universal service obligation embedded in licenses, concessions, or service contracts, with defined service areas, access targets, service standards, and enforcement. The second is a cost-of-service regime in which the provider's allowed revenue requirement—not the end-user tariff—is anchored in the efficient cost of service. Customers pay an affordable regulated tariff or service fee, with parity between grid and decentralized customers used where it is adopted as an explicit social-policy choice, and the difference is covered by an explicit subsidy. The third is the rigorous separation of the viability gap from the financing need: the viability gap is the recurring support required to keep service affordable, while the financing need is the capital structure required to build and renew the assets. Each must be tracked against its own instrument. The fourth is a pooled, ring-fenced settlement function—whether organized as Finance-Co, a strengthened rural electrification fund, or another dedicated vehicle—that provides payment security and makes cross-subsidies auditable. The fifth is a utility-like treatment of off-grid supply: mini-grids and stand-alone systems are operated as regulated, permanent service obligations rather than one-off projects, planned and remunerated on the same cost-of-service basis as the grid.

Where these five elements are present, least-cost plans can be translated into financeable service obligations; where any is absent, plans remain vulnerable to the familiar failure modes of unfunded mandates, unaffordable tariffs, or non-bankable subsidies. The three cases do not show that every institutional form must be identical. They show that the architecture travels, while the institutional recipe must be adapted.

7.2. What is calibrated?

Five design choices, by contrast, are set to the binding constraint of each country, as summarized in Table 4. The **delivery split** between public and private operators responds to the capability of the incumbent: a single twenty-year concession to a privately operated Service-Co in Uganda; a 60/40 split between a constrained ZESCO and a private concessionaire in Zambia; and district-level CERI packages in Madagascar, implemented by private operators—HIER, and Africa GreenTec with CASIELEC—in coordination with JIRAMA and ADER. The **subsidy instrument** responds to the available fiscal and sectoral resources: tariff-backed surpluses and blended capital in Uganda, a 3 percent levy as the permanent domestic engine in Zambia, and the National Electricity Fund, strengthened by European and German concessional support, in Madagascar. **Grant intensity**—more precisely, the share of capital cost not left to be recovered through future regulated remuneration—ranges from a blended profile in Uganda, through the 90/20/50 split across Zambia's vehicles, to the high capital-subsidy shares of the two Malagasy districts. **Timing and the electrification target year** are calibrated in all three cases, because access speed must be traded against fiscal peaks, procurement capacity, and institutional absorption. And the **treatment of legacy obligations** is set by history: a buy-out negotiation in Uganda, a separate refinancing of supplier arrears and a retained pre-existing debt stock in Zambia, and a parallel utility-recovery plan in Madagascar.

In each country, the architecture is held constant and these choices are fitted to circumstance. The framework is therefore not a fixed prescription. It is a method for identifying the binding constraint, separating the financial layers, and selecting the institutional form that can make the service obligation bankable.

Table 4 Calibration matrix across the three applications: what the framework holds fixed and what it tunes.

Design dimension	Uganda	Zambia	Madagascar
Binding constraint	Expiring Umeme concession; buy-out and continuity	Distressed ZESCO balance sheet; thin rural revenue base	Lowest access; extreme dispersion; fragmented decentralized legacy; weak rural fund; minimal transmission backbone
Delivery split	Single 20-yr Service-Co concession over the national network	60% ZESCO / 40% PrivateCo (grid); off-grid SPV	District CERI concessions to private operators (HIER; AGT + CASIELEC), with JIRAMA and ADER
Subsidy instrument	Tariff-backed surpluses + blended capital	Donor / DFI grants + 3% Rural Electrification Levy (domestic cross-subsidy)	National Electricity Fund (FNE) + EU/German concessional support (TANGO)
Grant intensity to the initial CAPEX	Blended; grants front-loaded as first-loss	90% ZESCO / 20% PrivateCo / 50% off-grid	High (~77% and ~56% in the two districts); rising private share
Finance-Co form	Upgraded the existing Uganda Energy Credit Capitalisation Company (UECCC)	Ministry of Finance-anchored settlement vehicle	Strengthened FNE + TANGO transactional facility
Electrification target year	2030 vs 2040	2030 vs 2040	Phased rollout (yrs 1 / 4 / 7), tuned to absorption
Legacy treatment	Umeme RAB buy-out (USD 118 vs. 234 m disputed)	Supplier arrears (USD 2.25 bn) refinanced + pre-existing debt stock (USD 3.52 bn) retained; kept separate	JIRAMA arrears (~MGA 2.4 tn) via national recovery plan, kept separate
Invariant across all three: universal service obligation + cost-of-service revenue requirement + separation of the two gaps + utility-like treatment of off-grid supply + pooled, ring-fenced settlement (Finance-Co).			

Source: authors' synthesis of the Uganda, Zambia, and Madagascar applications.

8. Conclusion and policy recommendations

The three applications show a common implementation failure: least-cost plans often stop before they become financeable programs. They identify technologies, locations, and investment needs, but do not always define who must serve, what revenue that provider can recover, how affordability is funded, or how payments are secured over time. The value added of the framework is to supply that missing layer between planning, regulation, subsidy, and finance.

This is also where the "justice" claim becomes operational. Universal access is not made just by declaring it a social objective; it becomes just when the design protects affordability, imposes service obligations, funds the gap transparently, and gives providers a credible basis to operate, maintain, and replace assets. The recommendations below therefore translate the framework into a sequence for moving from an electrification roadmap to an investable access program.

8.1. From least-cost plan to bankable program

The first task is to diagnose the binding constraint. It may be an expiring concession, a distressed incumbent, a weak rural revenue base, limited absorption capacity, a thin transmission backbone, or a fragmented legacy of decentralized systems. The constraint matters because it determines the institutional recipe: the architecture is transferable, but the delivery model, subsidy instrument, pace, and risk allocation must be fitted to the country.

The second task is to turn access into an enforceable obligation. Licenses, concessions, or service contracts should define service areas, connection targets, service standards, reliability requirements, reporting duties, consumer protections, and penalties for non-performance. Access should not depend on whether a developer later finds it commercially attractive to serve a household; it should be embedded in the instrument that grants the right to operate.

The third task is to separate what customers pay from what providers are entitled to recover. Cost-reflectivity should attach to the provider's allowed revenue, not necessarily to the end-user tariff. The regulator or contracting authority should approve the methodology for efficient costs, depreciation, replacement, pass-throughs, indexation, WACC, performance incentives, and true-ups. The customer tariff or service fee can then be set as an affordability decision. If it is below the efficient cost of service, the difference must be funded explicitly.

The fourth task is to keep the two gaps separate. The viability gap is the recurring difference between affordable customer payments and the allowed revenue required to provide the service. It should be funded through a predictable mechanism such as an access fund, sector levy, tariff-backed flow, budget transfer, or other ring-fenced source. The financing need is different: it concerns the capital structure required to build, maintain, expand, and replace the assets. It should be addressed through grants, equity, concessional debt, commercial debt, tenors, grace periods, sculpted amortization, and liquidity support aligned with the recovery horizon. A recurrent viability gap should not be disguised as debt unless there is a dedicated repayment source, and capital grants should not be used to hide a structural tariff shortfall.

The fifth task is to secure payment. Whether organized as Finance-Co, a strengthened rural electrification fund, a credit vehicle, or another dedicated platform, the settlement function should collect the relevant flows, disburse subsidies against defined obligations, provide payment security, and make cross-subsidies auditable. Its purpose is to prevent subsidy-payment risk from becoming the dominant risk for investors and operators.

The sixth task is to treat legacy obligations separately. Existing utility debt, unpaid supplier invoices, concession buy-outs, and recovery plans may affect sector cash flows and creditworthiness, and should therefore be modeled and reported. But they should not be merged with the cost of new access. A historical sector deficit is not the same as the investment cost of the rollout or the viability gap of serving rural customers affordably.

The seventh task is to calibrate pace. A faster target accelerates inclusion but increases annual financing peaks, procurement pressure, and execution risk. A slower target may be more credible fiscally and institutionally, but it delays access and can shift replacement costs beyond the comparison horizon. The chosen pace should therefore be reported not only as a financing decision, but also as a distributional decision about how long households remain without service.

Finally, demand growth should be treated as part of the financial design. Productive-use support, appliance financing, local enterprise development, agricultural processing, cold chains, and public-service loads can improve utilization and reduce the subsidy requirement per unit of service. Demand stimulation is not an optional add-on; it is one of the ways a subsidized access program becomes more financially resilient over time.

Together, these elements do not remove the need for public support. They make that support explicit, predictable, and compatible with long-term public and private investment.

8.2. Conclusion

The persistent failure of technically sound electrification plans to reach implementation is not mainly an engineering problem, nor simply a shortage of capital. It is the absence of the regulatory, business model and financial layer that turns a plan into investable obligations: a delivery model, an allowed revenue framework, a subsidy mechanism, a financing structure, and a secure settlement process.

This paper has defined that layer as a transferable architecture. Its core elements are a binding universal service obligation; a cost-of-service regime in which providers recover efficient costs through allowed revenue rather than necessarily through cost-reflective end-user tariffs; a clear separation between the viability gap and the financing need; utility-like obligations for decentralized supply; and a ring-fenced settlement function that secures payments and makes subsidies transparent.

The applications to Uganda, Zambia, and Madagascar show that the same architecture can operate under very different constraints. Uganda highlights concession transition and continuity of service. Zambia shows how a distressed incumbent and inherited financial burden can be modeled without being confused with the cost of new access. Madagascar shows how the framework applies where the national grid is too thin to be the main anchor and decentralized territorial systems become central. The institutional recipes differ, but the underlying logic is the same.

The cases also clarify what financial sustainability means. Universal access does not require rural customers to pay the full efficient cost of service; that would defeat the affordability objective. Nor does it require permanent dependence on donor grants. It requires a transparent allocation of costs: customers pay an affordable regulated tariff or service fee, public mechanisms cover the explicit viability gap, and providers recover the efficient cost of meeting defined service obligations. Subsidy is not a failure of the model. Unfunded subsidy is.

This returns the paper to the *Goldilocks* logic with which it began. Universal access is therefore achieved through calibration, not through a single fixed formula: a pace fast enough to be just but not so compressed that it becomes unfinanceable; a subsidy large enough to make service bankable but disciplined enough to avoid waste; a tariff affordable to customers but embedded in a revenue framework that allows providers to maintain and replace assets; and a capital structure aligned with the actual recovery horizon.

The central claim is that affordability, inclusion, and financial sustainability need not be competing objectives. They become competing objectives when planning, regulation, and finance are designed separately. When they are designed as one system, rural access does not undermine viability; it becomes part of the design of viability. Universal electricity access is therefore not only a development objective or a humanitarian obligation. Properly structured, it is an achievable component of a just energy transition and a viable investment proposition.

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