MIT CEEPR
Center for Energy and Environmental Policy Research

WP-2026-21
Research Brief

Least-cost on Paper, Feasible in Practice? An Iterative Framework Linking Electrification Planning, Regulation, and Finance for Universal Access

Santos J. Díaz-Pastor and Ignacio J. Pérez-Arriaga

Universal electricity access requires business models that can reach every unelectrified community and sustain affordable service over time. Least-cost techno-economic plans identify where to extend the national grid and where to provide off-grid service through local mini-grids or stand-alone solar home systems. They compare these modes across a territory to meet expected demand at the lowest total cost, now and in the years ahead. Yet these plans are often treated as fixed before the tariffs, business models, and financing terms needed to implement them are established. This paper develops an iterative procedure that makes the least-cost plan, the regulation and business model, and the financing plan consistent with one another. The objective is a comprehensive electrification approach that can sustain affordable service and remain financially viable, with credible funding commitments throughout the rollout and beyond.

In 2024, 655 million people had no electricity. If current trends continue, around 645 million will still lack it in 2030, 85% of them in Sub-Saharan Africa (IEA et al., 2026). Reaching them requires more than choosing the right infrastructure. Planning agencies, typically ministries of energy or rural electrification agencies, use geospatial models to compare three electrification modes for each unelectrified community: extending the national grid, building a mini-grid—a local network with its own generation—or serving households with stand-alone solar home systems. The result is a least-cost techno-economic plan: which mode should serve each community, at what level of service, and when (see Figure 1).

These techno-economic plans necessarily simplify the implementation problem. Many planning models compare the three electrification modes with a single discount rate. They are also often developed before decisions have been made about who will build and operate each system, what end-user tariffs will apply, who will cover any gap between customer revenues and costs, and on what terms financing will be available. The resulting least-cost plan therefore relies on two major assumptions that these models typically do not test: that differences in financing costs across electrification modes will not alter the least-cost allocation, and that households will consume the projected amount of electricity at the tariffs ultimately required, given the available subsidies. Decisions about the regulatory and business model may also impact financing and create constraints to the techno-economic plan. Once the business model, tariffs, and financing terms are specified, either assumption may no longer hold. If the first assumption fails, the least-cost allocation changes (Agutu et al., 2022); if the second fails, projected demand may not materialize, or the intended service may prove unaffordable without additional support.

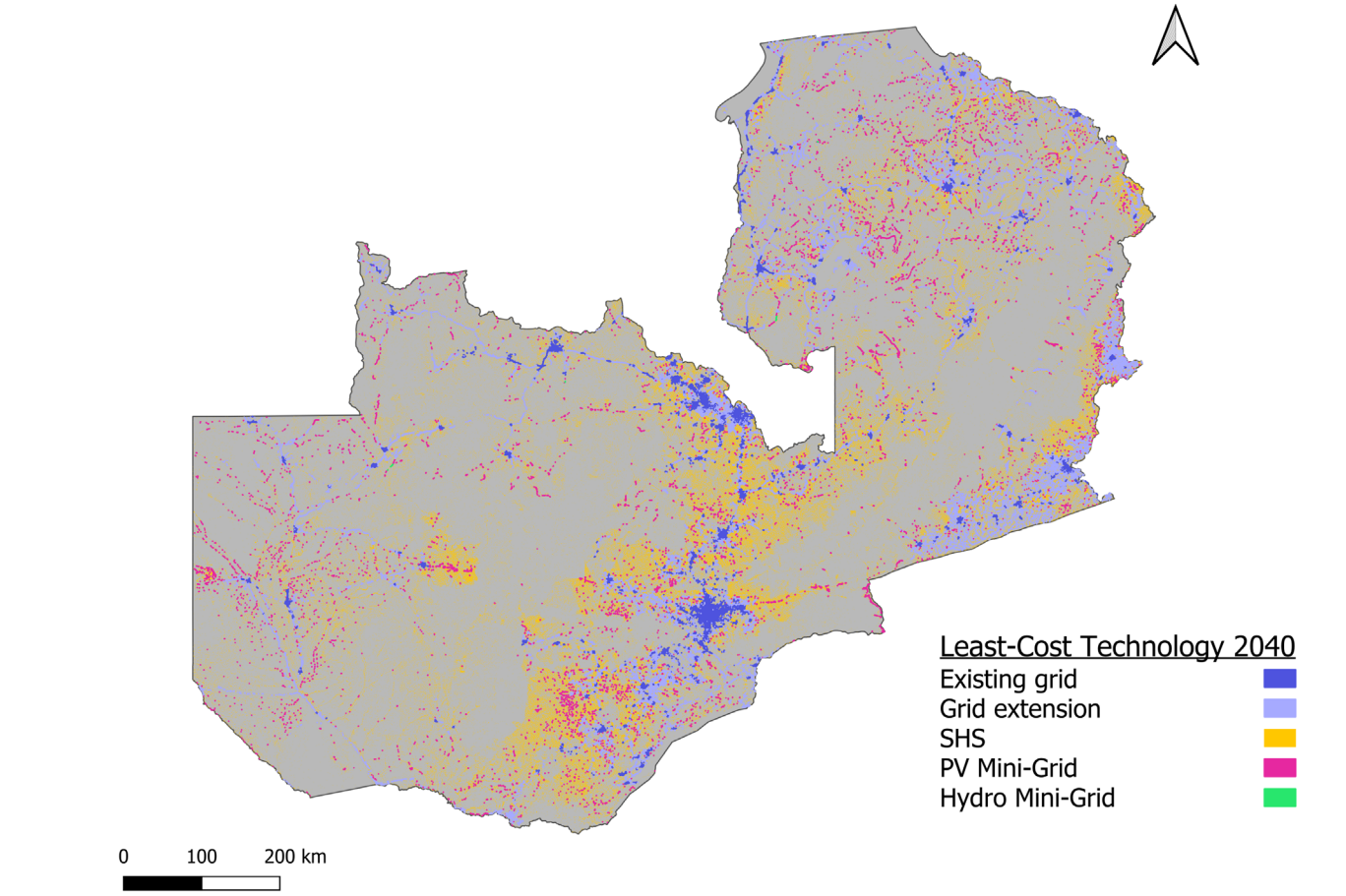


Figure 1. Least-cost electrification allocation across Zambia. Each unelectrified community is assigned to grid extension, a mini-grid, or solar home systems by the national least-cost plan for 2040, computed at a uniform 10% discount rate.

A process with multiple interrelated steps

Designing an implementable electrification program requires three major interrelated steps. The first produces a least-cost techno-economic plan: what to build, where, when, and at what cost. The second establishes the regulatory and business model: who is responsible for providing the service, what end-user tariffs apply, how costs are recovered, and how subsidies and risks are allocated. The third develops and tests the financing plan. It projects annual cash flows to assess whether customer revenues and public support are sufficient and reliable enough to cover costs, service debt, and earn the cost of capital. In practice, these steps overlap. What matters is not the order in which they are undertaken, but whether findings from one step require revising the assumptions and inputs used in another.

Building on earlier work by the authors (Díaz-Pastor et al., 2026), the paper formalizes the feedback between steps into an iterative procedure with two loops. When the financing step reveals that the proposed program fails one of its requirements—for example, households cannot afford the intended service, or revenues combined with public support are not sufficient to cover its costs—the procedure first examines whether the shortfall can be addressed without revising the least-cost plan. This may involve adjusting end-user tariffs, subsidy levels, contracts, risk allocation, or financing terms. If these changes resolve the shortfall, what is built, where, and when remains unchanged. Instead, the adjustments determine how the investment is financed and how its costs and risks are shared among households, public authorities, and investors. This is the "fast" loop.

If no viable financial plan can be obtained in this way, the least-cost plan itself must be reconsidered: the electrification mode of some communities, the service level, or the investment schedule. This is the "slow" loop, which reopens decisions about what is built, where, and when. "Fast" and "slow" refer to the scope of the revision, not to how long it takes. After either loop, the revised program is tested again

against the same requirements: households must be able to afford the intended service, private developers must be able to raise capital and meet their payments when due, public commitments must be credible, and the rollout must be realistic to build. The regulatory and business model must also work: for example, concessions that developers will bid for, or a clear division of grid extension between concessionaires and the incumbent utility. If the tested revisions still fail, the procedure identifies the constraints preventing implementation under the assumed conditions.

The first Zambia application illustrates the slow loop. The starting point is the national least-cost plan prepared by the African School of Regulation and SEforALL using data from the Rural Electrification Master Plan (MoE and REA, 2026), shown in Figure 1. The plan totals about USD 3 billion in capital expenditure and was computed using a uniform 10% discount rate across all electrification modes.

In practice, however, the entities that would deliver each mode do not raise capital on the same terms. The national utility that extends the grid can borrow through sovereign and concessional windows, whereas the private developers that build mini-grids and solar home systems face commercial rates, shorter maturities, and weaker payment security. The paper therefore re-evaluates the plan using a cost of capital specific to each business model: 10% for utility-led grid extension, 22% for privately developed mini-grids, and 18% for privately provided solar home systems. These are scenario assumptions rather than observed financing terms.

Under the proposed procedure, regulatory and financing measures—such as enforceable contracts, payment security, and concessional debt—would first be considered to lower the cost of capital of the private developers without changing the plan. Under the assumed rates, the annualized cost per kilowatt-hour of mini-grids, which are capital-intensive and face the highest rate, rises most. Communities near the existing network that the initial plan assigned to mini-grids are reassigned mainly to grid extension, and total capital expenditure rises from USD 3.00 to 3.34 billion (see Figure 2).

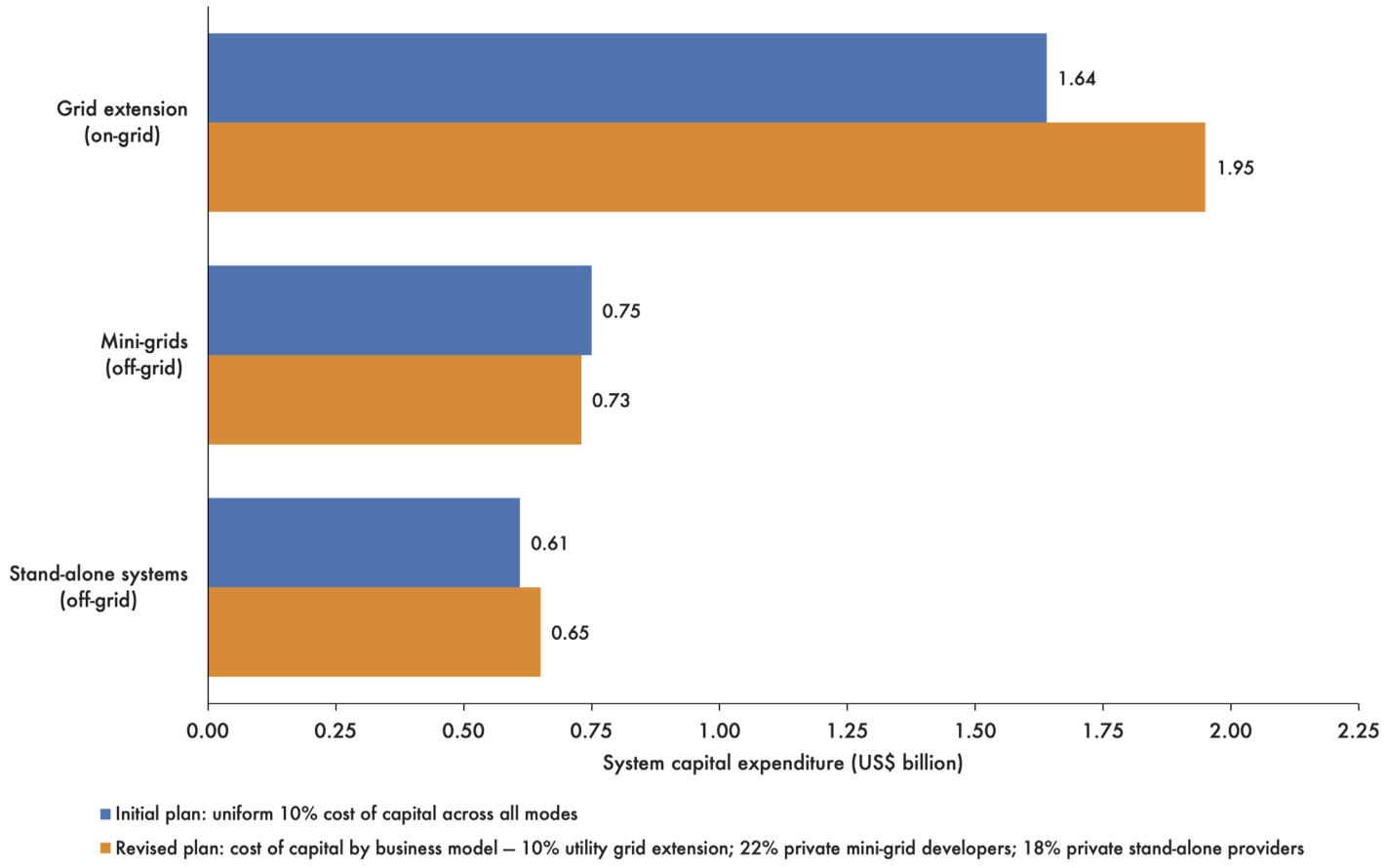


Figure 2. Financing assumptions change the investment allocation. Zambia national least-cost plan: system capital expenditure by electrification mode under a uniform 10% discount rate and under the cost of capital assumed for each business model. System capital expenditure rises from USD 3.00 to 3.34 billion.

The redesigned plan is therefore the least-cost allocation under these financing assumptions. It requires more capital expenditure because grid extension costs more to build in these communities but, evaluated at the assumed 10% cost of capital, becomes less expensive over the asset life than a mini-grid evaluated at 22%. The result is not that grid extension is generally better. It is that financing conditions can change which mode is least-cost. However, this redesigned allocation is not yet a financially validated program. With USD 0.34 billion in additional capital expenditure, the redesigned plan would need to return to the regulatory and financing steps to test whether the required investment can be financed and whether the resulting tariffs and public support are viable. The paper stops at the redesigned plan and leaves that assessment for the next iteration.

The second Zambia application illustrates the fast loop. The Chitambo pilot, in Central Province, reaches about 1,700 mini-grid connections and 3,300 solar home systems by 2045. Unlike the first application, the least-cost plan is kept fixed—the same connections, investment schedule, and initial investment—and, with the developer's equity also held constant, two alternative regulatory and financial packages are tested for both mini-grids and solar home systems. In both rounds, each household has an electricity budget of USD 2 a month in 2026, growing 2% a year with income, and is expected to consume 10 kWh a month in 2026, rising to about 15 by 2045.

The first round represents a capital-grant and cost-recovery tariff approach commonly used for off-grid electrification. A capital grant covers 80% of the initial investment, disbursed as connections are verified, and the mini-grid tariff is calculated each year to recover the developer's remaining cost of service. The model computes that tariff; it does not assume that the regulator approves it. The tariff ranges from USD 0.35 to 0.57 per kilowatt-hour (kWh) over the period and averages about USD 0.50. Because each household spends its whole electricity budget, at these tariffs it buys between 4 and 8 kWh a month, about 5 on average, well below the expected consumption. A higher tariff does not raise what households pay; it reduces the electricity they can buy. The business model also relies on sales to businesses and other non-residential customers to recover the remaining costs, assuming those sales materialize. The package fails the affordability check, but the constraint does not necessarily require changing the least-cost plan. Instead, the regulatory and financial package can be revised through the fast loop.

In the second round, the model assumes a regulated mini-grid tariff of USD 0.20/kWh, constant in real terms, so that households can buy their expected consumption within their budget. This is the affordability-anchored case: the tariff is determined by what households can pay rather than by the developer's cost of service. The capital grant falls to 50% of the initial investment; with the developer's equity unchanged, more of the investment is financed with debt, about USD 0.45 million instead of 0.09 million. An annual revenue settlement—similar to the revenue reconciliation used by regulated utilities—pays the developer the difference between the revenue the tariff generates and the cost of service the regulator recognizes, net of the grant. The model computes how large that payment must be; it does not assume that government or donors have committed to pay it.

Under this second package, average mini-grid household consumption rises from about 5 to 12 kWh a month, while cumulative mini-grid electricity supplied increases by 57% over twenty years (see Table 1). Despite the reduction in the upfront capital grant, total public support rises from USD 0.95 to 1.56 million in constant 2026 dollars, including an annual revenue settlement averaging USD 48,000. The second round passes the affordability check, but its financial viability still depends on access to the additional debt financing and credible public commitments to make the annual payments when due. The comparison therefore shows that making electricity affordable does not eliminate the cost of providing it: the revenues assumed by a business model, whether from customers or public funds, must be reliably generated and paid when due.

The two applications show why consistency between the least-cost plan, the regulatory and business model, and the financing is essential for implementation. Identifying an inconsistency is not enough: its cause determines whether the regulatory and financial package can be revised while keeping the plan fixed, as in Chitambo, or whether the least-cost allocation itself needs to be reconsidered, as in the national case.

Three implications follow. Planning agencies need to account for the cost of capital associated with each business model before treating electrification modes and investment schedules as settled. Regulators need to test separately whether providers can recover their cost of service and whether households can afford the intended service under the proposed tariffs and subsidy rules. Governments and donors need to judge public support by

Measure	Round 1: cost-recovery tariff case	Round 2: affordability-anchored case
Capital Grant	80% of initial investment	50% of initial investment
Mini-grid tariff	USD 0.50/kWh on average; set each year by the developer	USD 0.20/kWh; constant in real terms
Average mini-grid household consumption	About 5 kWh/month	About 12 kWh/month
Cumulative mini-grid electricity supplied	3.96 GWh	6.22 GWh (+57%)
Annual revenue settlement	None	USD 48,000 on average
Total public support: grant + settlement	**USD 0.95 million**	**USD 1.56 million**

Table 1. Chitambo pilot, Zambia, 2026–2045: the same least-cost plan under two regulatory–financial packages. Note: Both rounds keep the same connections, the same investment schedule, the same initial investment (USD 1.19 million), the same developer equity (USD 0.15 million), and the same household electricity budget. Cumulative electricity covers all mini-grid customers, residential and non-residential. The capital grant and the annual revenue settlement cover both the mini-grids and the solar home systems.

three things, not one: its total amount, its annual payment profile, and the duration for which funding can be credibly secured. How those payments will be sustained beyond the initial commitments must be resolved before developers are asked to invest.

Sustainable electrification does not require each system to recover its costs from its own customers. Instead, the long-term objective should be to recover the power sector's aggregate cost of service through regulated tariffs and cross-subsidies between customer groups, progressively reducing reliance on support from outside the sector. Until that is feasible, external subsidies must be explicit, reliably funded, and scheduled over the period for which they are needed. Their eventual phase-out should be consistent with affordability and sector-wide cost recovery, rather than simply assumed. The relevant policy test is not whether individual projects can be made financeable in isolation. It is whether the overall electrification program can continue toward universal access while sustaining affordable service, viable providers, and public commitments that remain credible over time.

References

Agutu, C., Egli, F., Williams, N. J., Schmidt, T. S., and Steffen, B. (2022). "Accounting for finance in electrification models for sub-Saharan Africa." Nature Energy 7:631–641. https://doi.org/10.1038/s41560-022-01041-6

Díaz-Pastor, S. J., de Abajo, C., Stoner, R., and Pérez-Arriaga, I. J. (2026). "From least-cost plans to implementable electrification: A regulatory–financial framework to achieve universal access." Utilities Policy 101:102221. https://doi.org/10.1016/j.jup.2026.102221

IEA, IRENA, UNSD, World Bank, and WHO (2026). Tracking SDG 7: The Energy Progress Report 2026. World Bank, Washington, DC. https://trackingsdg7.esmap.org/

MoE and REA (2026). Rural Electrification Master Plan (REMP) 2025–2030. Ministry of Energy and Rural Electrification Authority, Lusaka. https://www.moe.gov.zm/?p=5722

Link to the full working paper discussed in this brief:

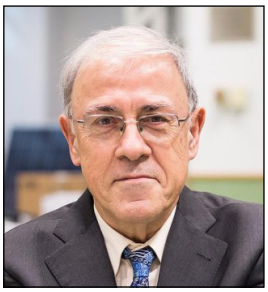
Díaz-Pastor, S. J. and Pérez-Arriaga, I. J. (2026), "Least-cost on Paper, Feasible in Practice? An Iterative Framework Linking Electrification Planning, Regulation, and Finance for Universal Access," MIT CEEPR Working Paper 2026-21, November 2026

About the Authors



Santos J. Díaz-Pastor is a research affiliate at the MIT Energy Initiative and a Ph.D. candidate at the Institute for Research in Technology (IIT) at Comillas Pontifical University in Spain. He has worked with governments and partners, including the World Bank, IDB, UNDP, GIZ, and the Rockefeller Foundation, to design electrification strategies, regulatory reforms, and investment plans in Latin America, Sub-Saharan Africa, and Southeast Asia.

During his Ph.D., he joined Impact Bridge Asset Management, where he helped invest a €150 million portfolio in clean energy, mobility, and social infrastructure. As an associate, he led the execution, diligence, and financial modeling with ESG and impact metrics of the pipeline. At the African School of Regulation, he serves as an Expert Associate, with a global footprint that includes projects in Madagascar, Zambia, Uganda and Rwanda. He holds a B.Sc. in Industrial Engineering from the Universidad Politécnica de Madrid and the Karlsruhe Institute of Technology (KIT) and a double M.Sc. in Industrial Engineering-Power Sector from Comillas.



Ignacio J. Pérez-Arriaga is Senior Advisor to the African School of Regulation (ASR) and led it as Interim Director from 2022 to 2024. He co-directs the MIT/Comillas Universal Energy Access Lab and taught at MIT from 2008 to 2022. At Universidad Pontificia Comillas he is Professor emeritus and founded the Institute for Research in Technology (IIT), which he directed from 1984 to 1994. He also serves as Professor and Director of Training at the Florence School of Regulation since its foundation in 2004.

An IEEE Fellow and Life Member of the Spanish Royal Academy of Engineering, Pérez-Arriaga has shaped power sector regulation through senior appointments in Spain, Ireland, and the European Union. He served as Commissioner at Spain's Electricity Regulatory Commission from 1995 to 2000 and as Independent Member of Ireland's Single Electricity Market Committee from 2007 to 2012. He also served on ACER's Board of Appeal from 2011 to 2016. He was Review Editor for the IPCC Fifth Assessment Report and led research for the Global Commission to End Energy Poverty from 2018 to 2022. He has advised and taught in over 50 countries and authored more than 200 papers. He holds an MS and PhD in Electrical Engineering from MIT and a degree in Electrical Engineering from Comillas University in Madrid.

About the Center for Energy and Environmental Policy Research (CEEPR)

Since 1977, CEEPR has been a focal point for research on energy and environmental policy at MIT. CEEPR promotes rigorous, objective research for improved decision making in government and the private sector, and secures the relevance of its work through close cooperation with industry partners from around the globe. CEEPR is jointly sponsored at MIT by the MIT Energy Initiative (MITEI), the Department of Economics, and the Sloan School of Management.