

Mission 300's Missing Demand

How Mission 300's Compacts Could Increase Fiscal Risk

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Executive summary

Mission 300, led by the World Bank Group and the African Development Bank Group, aims to connect 300 million people in Africa to electricity by 2030. To date, thirty-five¹ African governments have committed to Energy Compacts – country-led documents which describe the investments and reforms needed to attain the Mission’s objectives.

Mission 300 requires large investment – 2 to 7 percent of annual GDP across the four countries examined here. The highest share will fall on the most fiscally constrained countries. The World Bank and the African Development Bank plan to allocate around \$48 billion to the program through 2030. Mission 300 also aims to attract private capital at scale, which the World Bank estimates will need to represent around 50% of the program's investment volume.

Electricity infrastructure is dominated by fixed and sunk costs – if demand falls short of projections used to size investment projects, the shortfall becomes a fiscal cost. The fiscal cost is either supported directly where the state finances the assets, or contingently through the de-risking instruments that private capital requires.

Empirical evidence suggests that connection rates within rural electrified areas tend to be bimodal – either close to universal or close to zero – and consumption among newly connected low-income households tends to be low and slow to rise. This will not be the case everywhere, and does not mean that all electricity infrastructure investments described by the Compacts will not be financially viable. However, it does mean that electricity infrastructure investments need to be assessed against empirically grounded demand estimates, and that the Compacts' envisaged investments should be stress-tested for their impact on utility and sovereign debt.

We find no evidence that either the direct or contingent implications of these Compacts' investments for utility financial viability and for the sovereign have been measured. Across the four Compacts reviewed in detail by this policy note (Malawi, Zambia, Senegal, Tanzania), demand assumptions are either optimistic or absent. They are rarely decomposed into connection and consumption or stress-tested against different demand scenarios, and do not seem to be tested against the cost-reflective tariffs the same Compacts commit to. All four Compacts analyzed in detail discuss instruments that transfer demand or currency risk toward the public balance sheet, but do not discuss their costs or who provides them. Nor is direct fiscal risk – from publicly financed investments – sized.

The gist of this paper is that while returns to electricity investment can be large, they can also be overestimated, leading to future fiscal risks. The academic literature shows that, under certain conditions, electrification can deliver large social returns that justify subsidies where connections are not commercially viable. However, it also cautions that these returns should be assessed and that subsidy requirements should be budgeted for upfront.

The World Bank should continue to support a Mission-driven, country-owned strategy to increase electrification. However, it could do that while limiting future fiscal risks. There are four concrete steps

¹ Publicly available Compacts in October 2026

that the World Bank could take to manage these risks while fulfilling its commitments in a realistic manner.

1. Model demand explicitly and make the fiscal implications explicit and testable:

- **First, model demand explicitly, decomposing it into connection and consumption assumptions.** Those assumptions should be stress-tested against different scenarios of realized demand – including empirically observed rates of connection and consumption – to bound plausible ranges. Cost-reflective tariffs need to be well defined and explicitly tested: if they do not align with the ability to pay, that is important information, as it implies the need for a subsidy.
- **Second, cost the fiscal implications and subsidies required to reach a given policy objective.** An access goal (for instance, connecting X million people to electricity in Y region) is legitimate, but Compacts should estimate the impact on utility and sovereign debt, decomposing direct and contingent fiscal risk. This mirrors the World Bank's (2026) call for *"better and more comprehensive accounting of subsidies"*.

2. Sequence investment by demand: When the government fiscal situation is fragile, or when utilities are weak, investment should be deployed first where cost-recoverable demand – which may especially come from reliability improvements for firms – is demonstrated. Consumers with lower ability to pay – such as rural households – can be reached once utility finances are stabilized, through explicit, budgeted social programs (as suggested by Blimpo (Afronomics, 2025) and Opalo (2025)).

3. Make new data available to improve understanding of connection and consumption patterns and what drives them: more centralized data on electricity consumption patterns is becoming available. Making anonymized data available to researchers and development partners could help provide more precise data to guide electricity infrastructure planning.

4. Explore the use of the modularity of mini-grids to hedge demand uncertainty: mini-grids can be sized to initial demand and capacity staged as load grows, avoiding large fixed commitments against uncertain demand. This staged approach may also have costs – for example, we know little about how potential customers would react to connection or quantity rationing, even if for a short amount of time. Given the level of prediction error typically associated with mini-grid deployment and the costs associated with a mis-optimized system, a staged capacity approach could, however, still be more cost-efficient than capacity derived from a single optimization. Our call in this recommendation is one for increasing the evidence base rather than direct policy action.

Introduction

The large financing gap to achieve universal electricity access, combined with a cost of capital that makes it hard to close through markets alone, motivates coordinated action across multilateral development banks, national governments, and the private sector. Roughly 600 million people in Sub-Saharan Africa lack access to electricity, and new connections are barely keeping pace with population growth. Achieving universal access across Africa by 2035 will require around \$15 billion per year, compared with the roughly \$2.5 billion committed in 2023 (IEA, 2025). Utilities – which already struggle to cover existing debt service – and public budgets – in a context of high public debt – cannot close a gap this large on their own. Private capital is expensive: the cost of capital for African energy projects can run up to four times higher than in advanced economies, reflecting both actual and perceived country- and project-level risk (IEA, 2025).

Mission 300, launched jointly by the World Bank Group and the African Development Bank Group, is the most ambitious institutional response to this challenge to date. It aims to connect 300 million people in Africa to electricity by 2030.

National Energy Compacts, which deploy Mission 300 at the country level, highlight large investment needs: for the four countries reviewed in detail here, estimated Compact costs range from 2 to 7 percent of GDP. The highest shares fall on the most fiscally constrained countries. The World Bank and the African Development Bank plan to allocate around \$48 billion to the program through 2030². Mission 300 also aims to attract private capital at scale, which the World Bank estimates will need to account for about 50% of the program's investment volume. In the four countries we review in depth in this note, private financing needs are estimated to range from 32% to 79% of total investment.

The Compacts pursue both expanded access and utility financial viability, which may be contradictory as empirical evidence suggests that connecting low-income households may require subsidies. This erodes utility financial viability. Electricity demand in newly electrified areas is hard to predict, but empirical evidence suggests that connection rates tend to be bimodal – either close to universal or close to zero – and consumption among newly connected low-income households tends to be low and slow to rise. This contradiction is compounded by the economics of electricity infrastructure, which are dominated by fixed and sunk costs.

If demand is not sufficient to make the investments financially viable, the gap translates into fiscal risk – which the Compacts do not discuss or cost. This fiscal risk can be direct, for public investments (stranded assets or debt to keep tariffs affordable), or contingent, for private investments (through the de-risking instruments). The Compacts quantify neither. In the current context of high public debt and rising debt service costs, the financial shortfall may fall on countries with little fiscal space to carry it. In fiscally constrained countries, the consequences can be severe: Zambia's utility ZESCO – saddled with debt accumulated as below-cost tariffs failed to cover its dollar-denominated obligations – is currently classified by the IMF as a "significant fiscal risk" (IMF, 2026). By the end of 2021, the utility had accumulated some \$2.9 billion in debt and payment arrears (IMF, 2022).

² <https://www.worldbank.org/en/news/press-release/2025/01/28/heads-of-state-commit-to-concrete-plans-to-transform-africa-s-energy-sector-with-strong-backing-from-global-partners>

We argue that both the demand analysis and the fiscal implications of large infrastructure programs, such as Mission 300, should be explicit and testable. We do not argue that expanding access or restoring utility viability is inherently wrong, nor that all electricity infrastructure investments described in the Compacts will be financially viable.

This note builds on existing analysis of the contradictions and fiscal risks of Mission 300. Opalo (2025), Moss (2025), and Blimpo (Afronomics, 2025) argue that Mission 300 targets ambitious connection counts and risks failing to deliver on its own objectives of growth and jobs. Opalo (2025) and Blimpo (Afronomics, 2025) go further, warning that a focus on household connections creates fiscal risk – higher debt and unaffordable subsidies – because low-income households connect and consume little at cost-reflective prices. We trace, Compact by Compact, how the demand assumptions behind the connection targets go largely untested. We then show how such assumptions translate into fiscal risk that remains unquantified – direct when the state finances the assets, contingent through the de-risking instruments private capital requires.

Four recommendations follow. The first is to model demand explicitly and make the fiscal implications explicit and testable. This mirrors the World Bank’s (2026) doctrine for subsidy transparency. Accurately estimating consumption in to-be-electrified areas is challenging; however, this does not mean that useful demand analysis is impossible, especially when used to size the potential impact of an investment on utility and sovereign debt. The following three recommendations suggest ways to mitigate demand uncertainty. The second is to sequence investment when the government’s fiscal situation is fragile or utilities are weak. This sequencing can first target areas with demonstrated high demand, as suggested by Opalo (2025). Once utility finances have stabilized, expansion could then target lower-demand areas through explicit social programs. Third, we recommend making new data public and using it to improve understanding of connection and consumption patterns and what drives them. In many countries, prepaid metering means this data is now centralized, and anonymized consumption data could be made public. Our last recommendation is to increase the evidence base rather than take direct policy action – exploring the use of the modularity of mini-grids to hedge demand uncertainty. Although these systems are technically modular – and may therefore be deployed at a small scale in areas where demand is uncertain and scaled as demand grows – there is little research on the costs and benefits of such an approach to mini-grid deployment.

This note examines Mission 300 at the program design level and, for four countries – Malawi, Zambia, Senegal, and Tanzania – at the country-specific level. The first is the program design level – the 300 million connections target, the financing architecture and private capital mobilization, as well as the broader economic environment. The second is the country-specific implementation level, for which the note draws on a detailed review – notably of demand assumptions – of four Compacts: Malawi, Zambia, Senegal, and Tanzania. These were selected to represent a broad range of fiscal positions, from IDA grant-only sovereigns at high distress risk to comparatively stronger middle-income economies.

1. What is Mission 300?

1.1. How the program is structured

Mission 300 aims to coordinate the World Bank Group, the African Development Bank Group, national governments, the private sector and development partners to rapidly increase the pace of electrification in Africa. Mission 300 is led by the World Bank Group (including the Bank, the IFC, MIGA and Zafiri, an investment facility to support off-grid technologies³) and the African Development Bank Group, with support from the Rockefeller Foundation, Sustainable Energy for All and the Global Energy Alliance. The World Bank Group and the African Development Bank Group plan to allocate around \$48 billion to the program through 2030; they will also “provide technical assistance and coordination support to help African governments prepare and implement their National Energy Compacts, track progress across participating countries, and mobilize private investment”⁴. World Bank Group direct and private-sector leveraged financing aims to connect 250 million people, while the African Development Bank aims to connect 50 million⁵. By combining sector reform, public financing, and de-risking instruments, Mission 300 aims to attract private capital at scale⁶. The World Bank estimates that private capital will need to account for about 50% of the program's investment volume⁷.

Mission 300 is deployed at the country level through National Energy Compacts, country-level documents that set government commitments to quantitative targets (connections, renewable share, utility performance, private investment). They identify the investment pipeline and commit to a package of sector reforms. The Compacts are organized around five reform pillars: last-mile access, through both on-grid and off-grid technologies; capacity expansion and cost reduction; regional integration and power trade; private sector participation; and financially viable utilities.

1.2. What are the constraints addressed by the “Mission”?

Constraint 1: The access gap is large

Reaching Mission 300's objectives will require a rapid acceleration of electrification. Roughly 600 million people in Sub-Saharan Africa lack access to electricity (IEA, 2026), and electrification gains barely keep pace with population growth. The four countries studied in depth here start far from universal access, though their ambition levels vary. For Tanzania and Senegal, the trajectories needed to reach Compact targets largely continue the historical trend. Malawi and Zambia, by contrast, require a steep break from the historical pace.

³ <https://thedocs.worldbank.org/en/doc/f5191bbf194fcec652d4f5afe98a4768-0360012025/original/Mission-300-Overview-021025-jp.pdf>

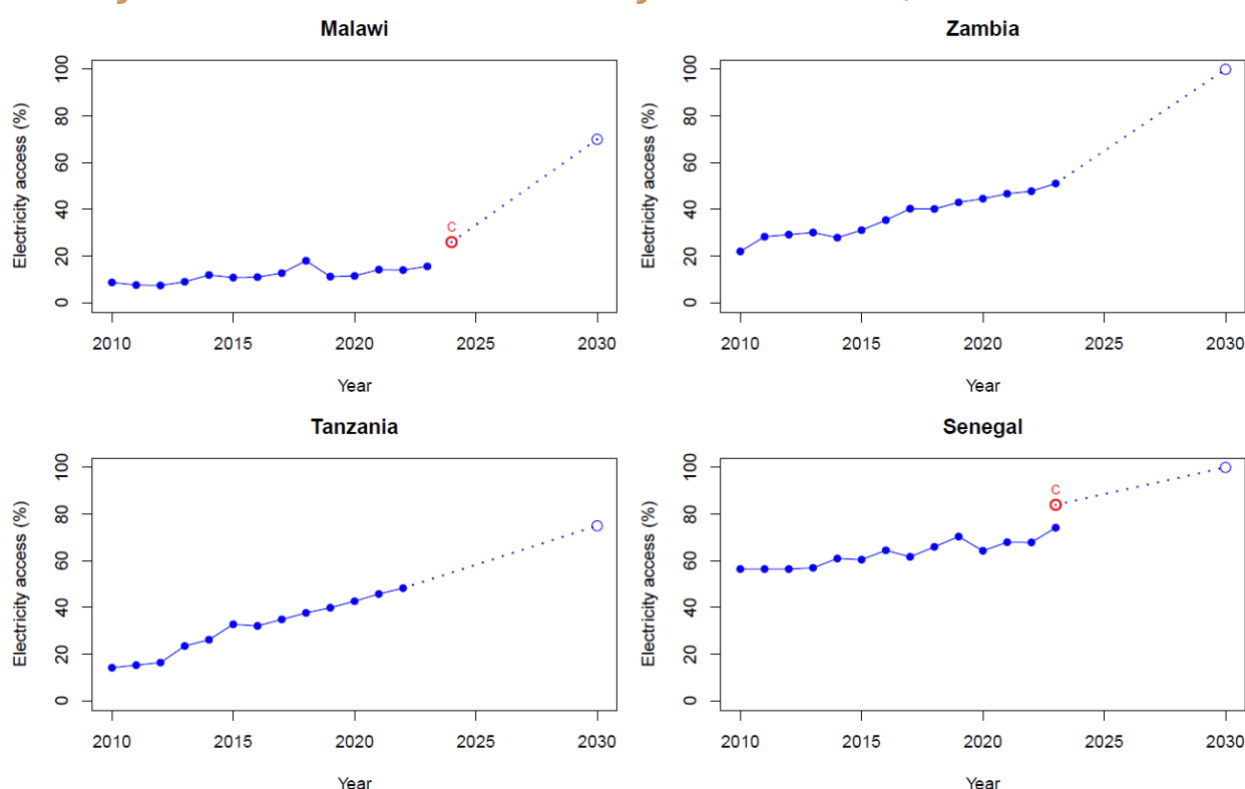
⁴ <https://www.worldbank.org/ext/en/energizingafrica/faq>

⁵ <https://www.worldbank.org/ext/en/energizingafrica/faq#1>

⁶ <https://www.banquemonnaie.org/fr/news/press-release/2026/06/16/under-mission-300-a-new-way-of-doing-business-connects-over-50-million-people-to-electricity-across-africa>

⁷ <https://www.worldbank.org/ext/en/energizingafrica/faq#1>

Figure 1: Historic connection rates and target connection rates, four focus countries



Notes: blue line: World Bank electrification data. Red hollow circles: access levels and targets reported in National Energy Compacts. For Malawi and Zambia, the Compact-reported baseline access rate (latest reported year) does not match the World Bank electrification rate for the same year (access to electricity, % of the population); we therefore do not interpolate between the two series.

Constraint 2: Utilities cannot carry the expansion on their own

Public money alone will not achieve universal access, and utility balance sheets will not close the gap. In 2023, only 13 of the 27 African utilities with available data covered operating and debt service costs before subsidies (World Bank UPBEAT, 2023). Utilities operating at or below cost recovery cannot invest in system refurbishment or maintenance, let alone add capacity to connect new customers.

Among the national utilities in our four focus countries, only one achieves cost recovery without public subsidies. Table 1 recaps UPBEAT data on operating and debt service cost recovery for the main public utilities of our four focus countries – only ZESCO manages to achieve cost recovery without public subsidies. Note that the subsidies published by the UPBEAT dataset are “as reported in utilities’ income statements” (ESMAP, 2025). This definition may understate the extent of public support, especially if it comes through regular liquidity injections rather than explicit per-connection or per-consumption-unit subsidies. It is also not clear whether cost-recovery covers costs owed (to IPPs, for example), or costs paid. This divergence may help explain why Zambia’s ZESCO shows no subsidies and cost-recovery in 2021, even though the utility accumulated debt and payment arrears during that period (see Box 4). For both reasons, the figures in the table below may overstate the extent of utility financial viability.

Table 1: Utility cost recovery, four focus countries

	Malawi	Zambia	Senegal	Tanzania
Utility	Electricity Supply Corporation of Malawi (ESCOM)	Zambia Electricity Supply Corporation (ZESCO)	Société Nationale d'Electricité du Sénégal (SENELEC)	Tanzania Electricity Supply Company (TANESCO)
Operating and debt service cost recovery, including subsidies	90%	107%	102%	101%
Operating and debt service cost recovery, excluding subsidies	87%	107%	99%	61%

Sources: Data from UPBEAT (World Bank). Notes: Last available year of data: 2021 for Zambia, 2022 for Malawi and Senegal, 2024 for Tanzania.

Constraint 3: Tight fiscal space

High public debt and rising debt service costs squeeze the fiscal space available for development investment. The financing gap for infrastructure and services is estimated at \$68 billion to \$108 billion (World Bank, 2025).

Compact costs are large relative to the size of the most fiscally constrained economies we study in detail. Compact costs are estimated at 7% of Zambia's annual GDP and 6% of Malawi's annual GDP. The public sector share alone accounts for between 6% and 19% of general government revenue. In markets in debt distress or at high risk of it (Malawi and Zambia), the public sector share alone exceeds current annual IDA allocations.

Table 2: Compact costs, GDP, IDA allocation and risk of external debt distress, four focus countries

	Malawi	Zambia	Senegal	Tanzania
Total compact cost	\$5.5 bn	\$11.9 bn	\$6.3 bn	\$12.9 bn
Yearly cost (total compact)	\$0.9 bn	\$2.0 bn	\$1.0 bn	\$2.15 bn
Yearly cost (total compact) as a share of GDP	6%	7%	3%	2%
Yearly cost (public sector share)	\$0.5 bn	\$0.4 bn	\$0.7 bn	\$1.5 bn
Yearly cost (public sector share), as a percentage of government revenue	19%	6%	10%	12%
IDA allocation (FY 2025)	\$0.3 bn	\$0.2 bn	\$0.2 bn	\$0.7 bn
Risk of external debt distress (IMF, 2026)	In debt distress	High	Moderate	Moderate

Sources: Total compact cost and public investment: national Energy Compacts. GDP, public government revenue: IMF WEO. IDA Allocation: final FY25 allocations. World Bank; SDR converted at 1.30 USD/SDR (IMF, first week 2025). DSA ratings: IMF LIC DSA list. Notes: Malawi public/private split imputed: private assumed equal to the sum of the first line of Compact Table 4 (\$2.5bn); public taken as residual. Yearly figures smoothed over six years (2025–2030 inclusive).

1.3. How the Compacts address the constraints

Technology choice

The Compacts draw on a variety of technologies – the centralized grid, mini-grids, and SHS systems – to reduce the cost of electrification. A planner extending access chooses between the central grid and off-grid solutions. Off-grid solutions divide into mini-grids – which retain the grid-like fixed-cost structure but are cheaper to deploy in less dense areas – and solar home systems (SHS), individual household solar kits. Least-cost technology varies with density: grid extension is cheapest in dense areas, mini-grids in intermediate ones, and SHS in the most dispersed. On average, a mini-grid deployed in Africa serves 458 connections (AMDA, 2024). Among Compacts that publish connection counts by technology type, all three technologies are used. In Malawi and Zambia, roughly half of planned new connections come through off-grid technologies (see Table 3). For Compacts that publish investment amounts by technology type, on-grid generation retains the bulk of investments (see Table 4).

Table 3: Compact new connections by technology type, three focus countries

	Malawi	Zambia	Senegal
Grid	1.2 M	1.5 M	3.9 M
Off-grid	1.6 M	1.8 M	2.8 M
Mini-grids	≈ 0.1 M	0.3 M	1.6 M
SHS	≈ 1.4 M	1.4 M	1.2 M
Total	2.7 M	3.2 M	6.7 M

Sources: Connections by technology: national energy Compacts. Notes: for Malawi, mini-grid connections: 13,500 per year x 6 years; for SHS : 244,000 per year x 6 years.

Table 4: Compact investment by technology and type, three focus countries

	Malawi	Zambia	Senegal
Generation	\$7,2 bn	\$3,3 bn	\$4.1 bn
Transmission	\$1,4 bn	\$ 0,1 bn	\$1.2 bn
Distribution	\$0.5 bn	\$ 0,8 bn	\$1.1 bn
Last mile	\$0.5 bn	\$ 0,8 bn	\$3.5 bn
Grid total	\$9.6 bn	\$ 4.9 bn	\$9.9 bn
Mini-grids	NA	\$ 0.4 bn	NA
SHS	NA	\$ 0.1 bn	NA
Off-grid total	\$2.1 bn	\$ 0.5 bn	\$0.1 bn

Sources: Investment by technology and type: national energy Compacts. Notes: For Senegal: Transmission assumed to be "Réseau électriques – Transport". Transmission assumed to be "Réseaux électriques – Moyenne Tension". Distribution assumed to be "Réseaux électriques – Basse Tension".

Utility viability

The Compacts commit to improving utility financial viability, notably by implementing cost-reflective tariffs. The implementation of cost-reflective tariffs is included in all four Compacts studied in depth by this note. The required increase in tariffs is sometimes large – Senegal's compact estimates that the average tariff would need to increase by 34%. Utility financial viability is a key indicator of private investment, as public utilities are often the sole client – "off-taker" – in privately financed

generation projects. In other words, utility financial viability may be a precondition for the strong private-sector investment called for by the Mission 300 Compacts.

Private capital

Private capital is one answer to the lack of utility and public finances needed to finance the large investments required to achieve Mission 300's goals. Public money is insufficient, utilities cannot finance expansion from their balance sheets, and the required scale is large. The Compacts largely rely on private capital and are designed around the conditions that would attract it, including public de-risking instruments and utility creditworthiness.

Given these ambitions, how can the investment be made in a fiscally sustainable way? The Compacts pursue rapid electrification and utility viability at cost-reflective tariffs simultaneously, at a scale that is large relative to the economies involved, and largely through mobilized private capital.

2. The demand problem

2.1. Electricity supply – fixed and sunk costs dominate

Building electricity infrastructure is largely fixed and sunk-cost dominated – meaning that financial viability is highly sensitive to how accurately demand is anticipated at the planning stage. The large fixed costs of electricity infrastructure – power plants to generate power and transmission and distribution lines to deliver it to where it is consumed – are spread over whatever volume is consumed. As a result, average cost per kWh declines with demand – if demand is lower than anticipated, the high fixed costs must be spread over fewer units. Electricity infrastructure designed for 50MWh of demand, where realized demand is 5 MWh, will have a per-unit cost several times higher than the investment case assumed. Electricity infrastructure is also a sunk cost – if demand disappoints, infrastructure is difficult to redeploy in another community, where demand may be higher. Raising prices to recoup oversizing may not be sufficient if demand is price-elastic – it may reduce demand – and the investor will face a loss. Transmission and generation infrastructure of the centralized grid also exhibit large economies of scale. The per-unit cost is lower in dense, urban areas than in rural, last-mile areas. The latter – the “electrification frontier” – is where a majority of the unelectrified live, and where the Mission 300 efforts will be targeted.

Mini-grids retain the fixed and sunk cost structure of the central grid, and oversizing reduces financial viability; however, they are technically scalable. The economies-of-scale problem may be less severe – generation, distribution, and consumption occur within the same geographical unit, so costs do not rise with distance as they do in centralized grids. A key advantage of mini-grids is that they are technically scalable. They can be sized to an initial (low) demand level and expanded if demand grows, although the costs and benefits of such an approach are not well studied. We return to this in Section 5.

Solar home systems (SHS) have different economics, and financial viability is less sensitive to how accurately demand is anticipated. These systems – which usually take the form of solar panels and DC-powered appliances, such as chargers, lights, fans, and TVs – are not infrastructure but consumer

durables. They are installed only when sold, meaning that overestimated demand will take the form of unsold inventory for the distributor. The cost of an SHS is also not necessarily sunk – an SHS that is not sold in one community can be sold in another. Poor anticipation of demand may result in fiscal loss – for example, through subsidies for SHS programs. However, the orders of magnitude at play are plausibly much lower than for grid infrastructure – an advanced SHS system typically costs between USD 100 and USD 300, whereas a mini-grid connection costs upwards of USD 1,000.

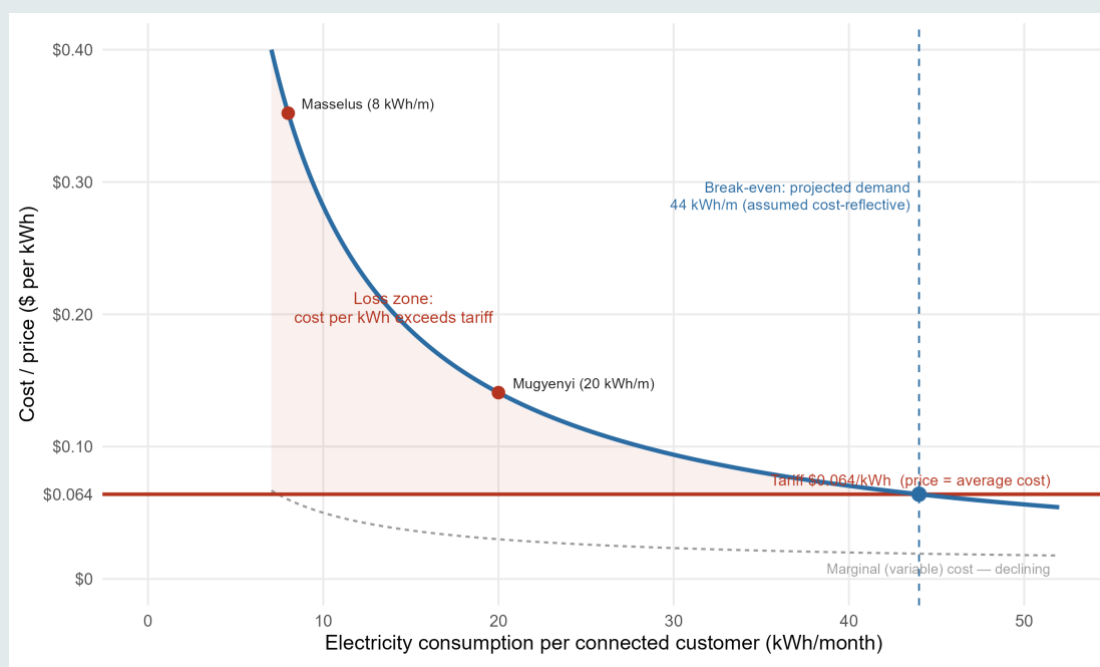
Although the cost of solar generation has fallen, this does not necessarily mean that all electrification investments have become financially viable. The cost of solar generation has fallen sharply and continues to fall, and is now competitive in terms of capital intensity with fossil-fuel generation (Ember, 2026) – an argument for deploying more renewables, which the Compacts also pursue. Cheaper generation lowers the cost of *generating* power. It does not, however, address demand barriers, including low willingness-to-pay for connection fees, which reflect electricity distribution costs. Nor does it automatically mean that consumption will increase – cheaper power, if translated into cheaper tariffs, will only increase demand if the tariff change is located in the price-elastic portion of the demand curve (it needs to be cheap *enough*). Whether an electricity investment is cost-effective depends on realized demand – both for connection and subsequent consumption – which we explore in the next section.

The remainder of this note therefore focuses on grid and mini-grid infrastructure (which we refer to as “grid infrastructure”), which share a similar fixed and sunk cost structure. This structure makes financial viability sensitive to the accuracy of demand forecasts at the planning stage. SHS systems do not share this structure, or at least not to the same extent – we therefore do not focus on these systems.

Box 1. Fixed costs and demand: an illustrative example for Malawi

To illustrate the effect of oversized demand assumptions on infrastructure profitability, we use Malawi's planning documents. These assume average consumption of roughly 44 kWh/month per connected low-income household priced at the current (non-cost-reflective tariff) of \$0.064, over a low-income population of around 1.7 M. For the sake of illustration, we treat this bundle – \$0.064kWh/month, 44kWh per customer, 1.7 M people – as if it were set for cost recovery – that is, we assume the tariff just covers the average cost of the infrastructure spread over 44 kWh across the low-income base of roughly 1.74 million customers. Under that assumption, the utility expects revenue of about \$57 million per year ($0.064 \times 1.74\text{m} \times 12 \times 44$) and sizes its infrastructure accordingly, on a financial case of (at least) zero return. At 44 kWh, the utility just breaks even: the tariff equals its average cost per kWh. Above 44 kWh, average cost (the blue curve) keeps falling as the fixed cost is spread over more units, so the infrastructure turns a profit that widens to the right.

Figure 2. Why low demand means losses: average cost, tariff, and demand for Malawi's low-income group



Now suppose realized consumption is only 20 kWh – the country-wide average observed in Rwanda by Mugenyi et al. (2025), in a country with income per capita approximately two times higher than Malawi. Revenue then falls to about \$26 million per year, while the fixed costs – and any debt service – remain due in full. If the tariff is kept at \$0.064, the utility loses \$0.076 on each kWh sold. Equivalently, the average cost of serving that customer rises to about \$0.14/kWh.

The fact that marginal revenue (the tariff) exceeds marginal cost (the cost of providing an additional kWh of electricity) does not mean the utility is profitable. Whether the utility earns or loses money depends on whether the tariff covers average total cost – and because fixed costs are high, average total cost lies well above marginal cost, especially at low levels of consumption.

Raising the tariff toward the level that would recover cost at low consumption risks running into price-elastic demand – especially for low-consuming customers.

2.2. Connection rates and consumption

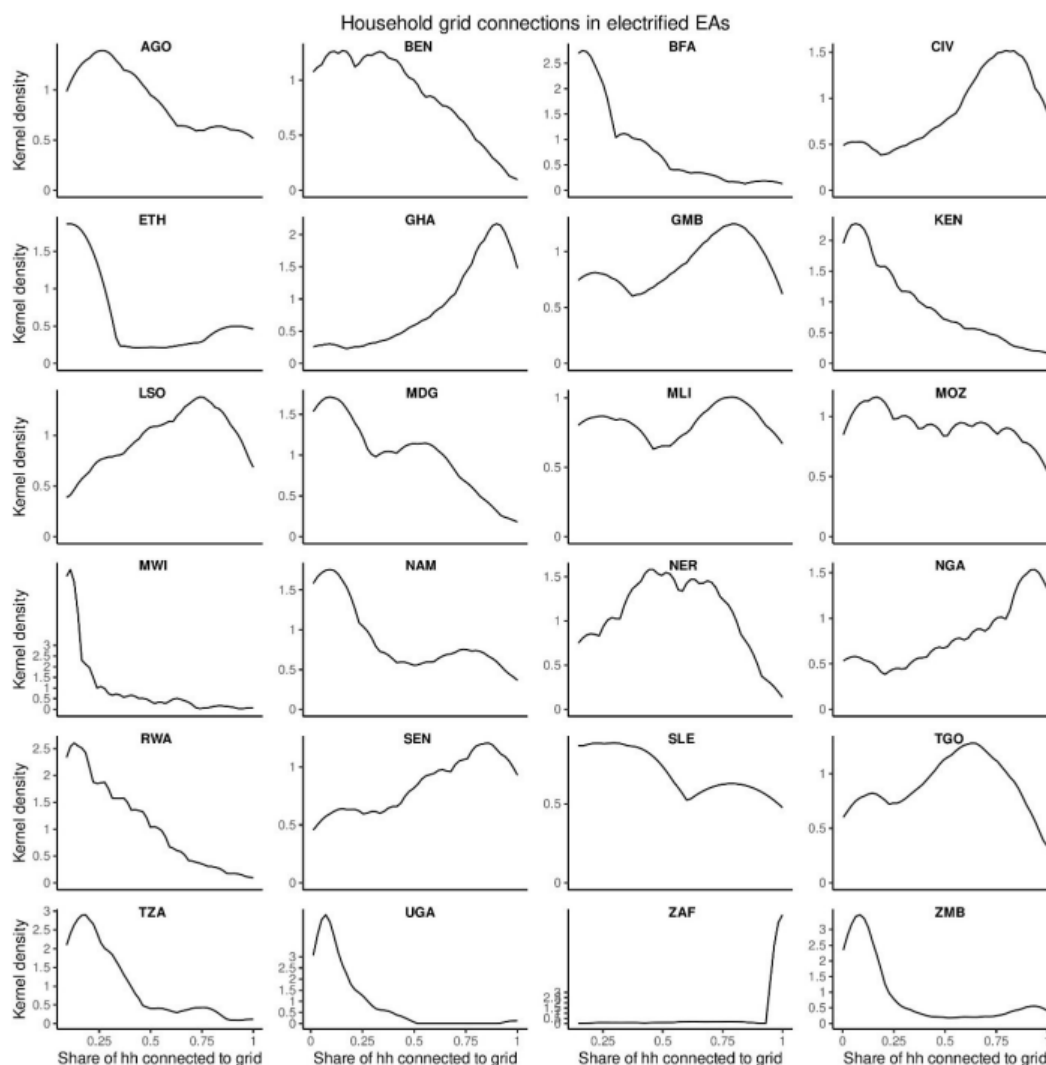
Demand for electricity can be broken down into two stages: connection and subsequent consumption. Evidence suggests that realized demand falls short of what these programs assume: not all households and businesses with access choose to connect, and those that do may consume very little. A program that oversizes infrastructure based on near-universal, high-consumption connections will underperform on both dimensions, compounding potential losses.

Step one: connection rates

Grid infrastructure extension does not automatically translate into grid infrastructure connection. The decision to connect involves upfront costs – connection fees, internal wiring, appliances – that are prohibitive for many low-income households and businesses, even when in electrified areas.

The same infrastructure can generate very different demand outcomes depending on local economic conditions. In Kenya, only fully subsidized connections generated near-universal uptake. Connections offered at even modest cost produced sharply lower demand: subsidies of 57% and 29% yielded uptake increases of just 23 and 6 percentage points respectively from a near-zero baseline (Lee et al., 2020a). Moneke and Figueiredo Walter (2024), whose findings Opalo (2025) also draws on, show that uptake rates within rural electrified areas are far from universal and tend to be bimodal: areas either achieve high connection rates or remain largely unconnected, with few cases clustering around an intermediate level (See Figure 3).

Figure 3 – Household grid connection rates in rural electrified areas, for 24 African countries



Source: Moneke and Figueiredo Walter (2024)

Step two: consumption conditional on connection

Even among households that do connect, electricity consumption in comparable low-income settings remains low and may stay that way for extended periods. Mugenyi et al. (2025) find that more recently connected customers consume less than earlier-connected ones, with average residential consumption falling from about 45 kWh/month to about 20 kWh/month between 2013 and 2019. Over a comparable period, Rwanda's electrification rate rose from 10 percent (2011) to 50 percent (2023), suggesting that the grid had already reached the most easily cost-recoverable households – and that later connections skew toward lower-consuming, harder-to-serve ones. Fobi et al. (2018) reach a similar conclusion in Kenya. Masselus et al. (2025) find consumption of approximately 96 kWh per year (8.0 kWh/month) ten years after grid rollout in rural Rwanda, suggesting that minimal consumption levels can persist over time in rural areas. Mugenyi et al. (2025) also provide evidence of moderately price-elastic demand in Rwanda for low-demand customers – nearly halving the tariff led

to a modest increase in consumption, suggesting that other factors – such as budgetary constraints or competition from off-grid solar – may play a role.

Box 2. Illustration: creating demand in the agricultural sector

Zambia's Compact projects agricultural electricity demand rising from 48 MW to 1,200 MW by 2030 – a 24-fold increase in six years. India's agricultural electricity consumption grew roughly 50-fold from 1969 to 2016 (Prayas Energy Group (2018)). India's trajectory, however, took nearly five decades, and it was driven by two important conditions that the Zambian case does not seem to replicate.

The first was a structural transformation of the agricultural sector. The Green Revolution significantly increased the profitability of irrigated agriculture, creating sustained "demand-pull" for electrified pumping as credit became available and productivity rose (Mukherji, 2020).

The second factor was price, for which Badiani et al. (2012) summarize the evidence. State Electricity Boards (SEBs) were statutorily required to earn a 3% return on capital under the 1948 Electricity Act. In practice, they ran persistent losses. By 2001, SEB losses reached nearly USD 6 billion, or 39.5% of revenues. SEB losses appear to have been driven by agricultural users, who consumed 32.5% of electricity but accounted for only 3.4% of revenue in 2000. By 2002, the revenue losses were estimated to be roughly a quarter of India's fiscal deficit. The Compact pursues cost-reflective tariffs – by design, the opposite policy.

When policy shifted in 2005 toward universal household electrification (the *Rajiv Gandhi Grameen Vidyutikaran Yojana*, or RGGVY), investment in irrigation technology was cut; this may have been due to financial (connection costs for farms no longer subsidized) or technical (transformers not sized to meet pump needs) limitations (Ray and Pullabhotla, 2023).

2.3. What the Compacts say – and do not say – about demand

A recurring feature of the planning underlying the Compacts is the use of least-cost optimization tools. These tools let a planner know the cheapest way to meet a given connection target, but do not indicate whether the demand at those connections will be sufficient to recover the cost of serving them.

Box 3. What's needed to scope demand risk

Three transparent assessments can be included in the Compacts to scope the demand risk:

- A demand assessment decomposed into (i) an assumption on the connection rate within electrified areas, (ii) consumption conditional on connection, and (iii) different scenarios of realized demand, including scenarios using empirically grounded estimates of demand, rather than a single aggregate MW projection.
- An assessment of how the path to cost-reflective tariffs affects that demand: what consumption would be at cost-reflective prices, not at today's subsidized ones.
- Inversely, an assessment of the subsidies required to hit the connection targets (the "affordability gap") – including both the up-front connection subsidy and the ongoing consumption subsidy.

Malawi

The Malawi Compact targets a large increase in access, from 25.9% to 70% by 2030. It aims to achieve this through 1.15M new grid connections and 1.55M off-grid, supported by 848 MW of new generation capacity. The Malawi Compact states that electrification planning uses an "updated" Integrated Energy Planning (IEP) tool, which it describes as ensuring planning is "*grounded in cost-effective and data-driven solutions*". The publicly accessible model – the 2022 IEP (SEforALL, 2023) – models universal access by 2030, not the Compact's 70% target. No other updated plan was identified online by the time of writing, or included for reference in the Compact. The publicly accessible model is therefore the 2022 IEP.

Several assumptions underpinning its demand estimates seem fragile and optimistic. The connection rate in electrified areas is set at 70% – which may seem high compared to the distribution of connected households in rural electrified areas in Malawi, see Figure 3 –, assumes connected households shift their full energy use to the grid, which requires appliance investment (e.g., electric cooking), which is far from guaranteed. Demand is projected at the current, non-cost-reflective tariff of \$0.064/kWh – raising the tariff to achieve cost-reflectivity would reduce demand. Mini-grid consumption is estimated at 12 kWh/month across all regions, with the acknowledgment that "*grants or subsidies may be necessary to close the affordability gap*" – without costing the gap. Since the updated model is not public, we do not know whether it updates any of this.

Zambia

The Zambia Compact targets universal access by 2030. It aims to achieve this through 1.5M new grid connections and 1.8M new off-grid connections. Drawing on the country's Integrated Resource Plan (IRP) from the Zambia Ministry of Energy (2023), it projects sectoral demand growth to 2030: agriculture from 48 MW to 1,200 MW; mining from 886 MW to 1,552 MW; industrial and commercial from 257 MW to 337 MW; and residential from 769 MW to 1,079 MW.

Both household and agricultural demand seem to be derived from government targets rather than from empirically grounded estimates. For households, the IRP notes that "*The GRZ has set an*

ambitious target of achieving universal access to electricity by 2030, and the IRP scenario is carefully designed to align with this objective". It therefore does not appear to include an estimate of connection rates, nor does it discuss how deviations from government targets could affect demand. Consumption is built from ZESCO meter-point demand data and analyzed by connection-year cohort, but appears to be derived under prevailing tariffs – the sensitivity of assumptions to cost-reflective tariffs is not tested. Agricultural sector energy demand projections seem particularly ambitious. The Compact projects a 25-fold increase in demand from the agricultural sector over six years. As Box 2 notes, agricultural electricity demand has historically grown at nothing like this pace, even under far more favorable conditions with subsidized tariffs.

Senegal

The Senegal Compact targets universal access by 2029. This is up from 84% in 2023 – reaching roughly 6.6 million additional people by 2030: 3.9 million (59%) via the grid, 1.6 million (23%) via mini-grids, and 1.2 million (18%) via solar home systems.

Senegal's least-cost tool is the Plan Intégré à Moindre Coût (PIMC), promised for 30 June 2025 – after the Compact was published. It was not available online at the time of writing. The Compact concedes that its uptake and consumption data are incomplete and commits to further surveys to "*improve project monitoring and planification*". However, the financing is already fixed – \$6.3bn, split by technology and by public/private source. Given that the PIMC was not delivered by the time the Compact was published – and the technology split committed – the question is whether the plan can still redirect a pipeline that is already costed.

Tanzania

Tanzania's Compact targets increasing electricity access from 46% in 2022 to 75% in 2030 and goes considerably further than the Malawi, Zambia, or Senegal documents in testing its demand assumptions. The Compact's electrification planning rests on the Power System Master Plan (PSMP), an update to which was due in 2025. A PSMP 2024 Update (Tanzania Ministry of Energy(2024)) is publicly available and is the most developed of the four planning documents reviewed here: it sets out explicit demand scenarios (Base, Low, and High cases), states its GDP growth assumptions (6.3% in the base case, tested against 5.2% and 7.1%), and models system losses, load factor, and the power requirements of emerging demand sources such as LNG, e-mobility, and clean cooking. The PSMP does not, however, appear to test its demand forecast against cost-reflective tariffs, nor to estimate the subsidy required to reach its access and connectivity targets. As with the other Compacts, the question of whether the demand it projects would materialize at prices that recover costs, and what the affordability gap would cost to close, seems to be left unaddressed.

3. From demand risk to fiscal risk

Scoping demand matters because shortfalls in realized demand ultimately translate into fiscal risks for sovereigns. Public investments create direct fiscal risk, and private investment may transfer risk to the public sector through de-risking instruments and guarantee obligations. The Compacts split investment between private and public sources in different proportions, from 32% private for Tanzania to 79% for Zambia.

Table 5: Compact investment by private and public sources

	Malawi	Zambia	Senegal	Tanzania
Private investment	\$2.5 bn (45%)	\$9.5 bn (79%)	\$2,3 bn (38%)	\$4,1 bn (32%)
Public investment	\$3 bn (55%)	\$2.4 bn (21%)	\$3,9 bn (62%)	\$8,8 bn (68%)
Total investment	\$5.5 bn	\$11.9 bn	\$6.3 bn	\$12.9 bn

Sources: Investment by private and public sources: national energy Compacts. Notes: Malawi public/private split imputed: private assumed equal to the sum of the first line of Compact Table 4 (\$2.5bn); public taken as residual.

3.1. Public capital deployed where demand cannot amortize it

For infrastructure financed by the public sector, the fiscal costs of unrealized demand are direct. Capital is deployed on the assumption that a certain volume of demand will materialize. If it does not, debt service continues while the investment generates no (or lower than predicted) returns. Schematically, lower returns may be driven by low connection and consumption (if tariffs are kept at cost-recoverable levels) or through below-cost recoverable tariffs (to stimulate demand). Where the infrastructure is debt-financed through concessional loans (such as loans which may be extended by the World Bank or the African Development Bank as part of Mission 300) or sovereign borrowing, repayments fall on the state irrespective of utilization. Where it is grant- or budget-financed, and particularly in the case of the fiscally constrained countries we study, the opportunity cost may be substantial.

3.2. Private capital, where it occurs, may transfer risk back to the public sector

To attract private investments, de-risking instruments – which transfer risk from a private investor to the public sector – are often included in energy Power Purchasing Agreements. The Compacts expect to attract large amounts of private investment (in the four countries we review in detail, up to 45% in Malawi and 79% in Zambia), notably to finance power generation projects. Private investments in generation are generally structured as Power Purchasing Agreements (PPAs) between an “off-taker” – the client, usually the national utility – and the private investor. These agreements, which are usually long – at least 20 years – allow investors to incorporate risks that make these projects unattractive: demand uncertainty, currency depreciation, off-taker creditworthiness, and political risk. Two classes of de-risking instruments are common in energy PPAs.

The first class of frequently used instruments are take-or-pay clauses. Under such agreements, the off-taker agrees to purchase a certain amount of electricity over a given time period, regardless of

whether that electricity is sold. If sales fall short of the contracted volume, or tariffs are held below cost, the utility pays for power whose cost it cannot recover from customers.

The second class of frequently used instruments are dollar-denominated contracts. These eliminate currency risk for the private investor, but transfer it entirely to the utility, which collects revenues in local currency. If the local currency depreciates, the utility will see a substantial increase in the (local-currency) price of its PPA electricity.

Box 4. The ZESCO precedent

The debt accumulated by ZESCO, Zambia's public utility, illustrates how these dynamics play out. Tariffs held below cost recovery, combined with high operating costs "largely driven by purchase agreements with IPPs," produced significant losses from 2018 to 2020 — losses compounded by the kwacha's depreciation against dollar-denominated payables. By the end of 2021, ZESCO's outstanding debt comprised direct loans (USD 1.5 billion) and USD 1.4 billion in payables to independent power producers (IMF, 2022). The mechanism is visible at the level of individual contracts: the 120 MW Itezhi-Tezhi plant, a joint venture between Tata Power and ZESCO, sold electricity to ZESCO at USD 0.093/kWh under a long-term PPA — well above the roughly USD 0.052/kWh at which ZESCO resells to end-users (World Bank, 2020), embedding a structural per-unit loss on every kilowatt-hour. ZESCO is now classified by the IMF as posing a "significant fiscal risk."

One response is to treat the ZESCO precedent as a design flaw that future contracts will avoid. However, the contract terms ZESCO offered may have been the price of attracting private capital to a high-risk environment. If the underlying conditions do not change, comparable contracts will require comparable protections to attract capital. Those conditions are unlikely to shift quickly. A fundamental improvement in demand — for instance, through rising household incomes — is highly uncertain over the short to medium run. Utility creditworthiness can improve faster, but only where investment is directed toward demand that can be served at cost-recovering rates.

3.3. What the Compacts say – and do not say – about de-risking

All four Compacts analyzed in detail discuss instruments that transfer demand or currency risk to the public balance sheet but do not estimate their costs. They generally do not specify which guarantee structures will be used. None of the Compacts analyzed discuss the scale of de-risking instruments, who provides them, or the contingent exposure they create for the sovereign.

Box 5. What's needed to scope the fiscal risk

None of the four Compacts lets a reader check its demand, tariff, and financing commitments against each other. Three assessments would be needed:

- How does the path to cost-reflective tariffs affect demand, and therefore cost recovery? If raising tariffs suppresses consumption, what does that do to the utility's bottom line, and how do the available strategies trade off against each other?
- What do the required subsidies cost — connection and consumption both — where the money comes from (cross-subsidy from industrial load? the general budget? donor grants?), and how does that flow through to utility and sovereign balance sheets?
- How do different demand scenarios trigger the de-risking instruments, and what does each scenario cost the sovereign?

Malawi

Malawi's Compact acknowledges its restricted ability to issue guarantees, but describes de-risking instruments it could use to support strategic private investments. Malawi's Compact explicitly acknowledges: *"macro-fiscal constraints have restricted the government's ability to issue state guarantees"*; the government *"has to prioritize projects that are high impact to ensure it is in compliance with the IMF program."* It simultaneously discusses several instruments whose fiscal cost it does not estimate: the Ngwee Ngwee Ngwee Fund; fiscal support for strategic private investments, including dollar-denominated contracts permitted on a case-by-case basis; and carbon-finance-based models.

Zambia

Zambia's Compact aims to mobilize private investment through "innovative financing mechanisms, including risk mitigation tools and bankable power purchase agreements". It also references the Open Access Framework, which would allow some private investors to bypass ZESCO as off-taker entirely — a structure that, for projects serving concentrated high-revenue demand such as mining, could limit public sector exposure. It would also mean that ZESCO may miss out on industrial clients, which may be the most profitable. Zambia's IRP concedes that if *"generation capacity becomes stranded (i.e. energy not sold to customers), but the cost of capacity will typically be passed on to Government and/or customers in any case as this is a requirement of the financing structure of such projects"*, without pricing this risk. Beyond these references, the Compact does not specify what risk mitigation tools will be used, who will provide them, or what contingent liabilities they would create.

Senegal

Senegal's Compact commits to innovative financing with guarantee instruments ("instruments de garantie") to create an enabling environment for private capital. For decentralized renewables specifically, the government commits to establishing, by the first quarter of 2026, a subsidy and financing mechanism to make private off-grid projects viable — an implicit acknowledgment that these projects are not financially viable absent such support.

Tanzania

Tanzania's Compact is the least specific about private-sector mobilization mechanisms. It references PPAs and PPP structures without providing details on what these would be or who would bear the risk.

4. Policy Implications and Recommendations

Electricity infrastructure is dominated by fixed and sunk costs, meaning that financial viability is highly sensitive to how accurately demand is anticipated at the planning stage. Oversizing relative to demand means those costs must be spread over fewer units; if demand disappoints, it is difficult to redeploy infrastructure to another community where demand may be higher. Demand is uncertain. On the evidence, it tends to fall short of what infrastructure programs assume, for two reasons – connection is far from universal even in electrified areas, and consumption among those who do connect tends to be low and to grow slowly.

In the context of electricity infrastructure, uncertain demand poses a risk to utility revenue and, ultimately, to sovereign balance sheets. That risk should be analyzed and disclosed, particularly given the scale of the Mission 300 investments. Using empirically grounded estimates of demand – and stress-testing demand assumptions against alternative scenarios – can help a planner determine whether an infrastructure investment is likely to be cost-recoverable and, if not, how large the shortfall is likely to be. The evidence suggests that cost recovery will not be achievable in many unelectrified areas. In some areas, demand will be strong enough that expanding access at broadly cost-recoverable rates is plausible; in others, it will not. Either way, the impact of investments on utility and sovereign balance sheets – both direct and contingent – should be quantified and disclosed.

The existence, in some contexts, of endogenous demand growth and social returns to electricity infrastructure suggests that these should be assessed ex-ante rather than assumed across the board. The more recent literature studying the economic effects of electrification (Meeks et al (2025), Fetter et al. (2024), Vanden Eynde and Wren-Lewis (2025)), suggests that expecting electricity infrastructure to endogenously create demand by increasing growth is a risky bet. In certain areas, with pre-existing complementary conditions such as access to roads and markets, electrification may drive firm and income growth. In other areas, the effects of electrification are weak. Overall, there is little evidence on precisely which pre-existing conditions are key to driving structural transformation. The argument that electrification may also carry social returns beyond the revenue it earns the utility is also sometimes made. Here again, the results are mixed. Some studies point to improved health (Barron and Torero, 2017), human development (Lipscomb et al., 2013), or school attendance (Khandker et al., 2013). Other, more recent studies find little or highly heterogeneous effects on socio-economic outcomes (Lee et al., 2020a; Koima, 2024; Burlig and Preonas, 2024). Several explanations have been proposed to explain the divergence in results. These include differences in study methods (with more recent studies usually employing more rigorous methods to establish causality), households' starting incomes (a certain threshold of income may need to be attained for a household to be able to make use of electricity), the presence of complementary interventions, and the quality of the power supplied. The implication here is not that electrification does not carry social returns, but rather that, similar to endogenous demand growth, these returns may only appear in specific contexts.

Suggestion 1: Model demand explicitly and make the fiscal implications explicit and testable

As set out above, this means two things the Compacts do not currently provide.

First, a demand assessment decomposed into assumed connection rates and consumption conditional on connection, including at cost-reflective tariffs. These should include demand estimates sourced from the academic and grey literature on connection rates and consumption levels observed in newly connected areas, rather than estimates backed out from policy objectives. Accurately estimating consumption in to-be-electrified areas is challenging. CrossBoundary (2019), leveraging 550 million data points across 62 mini-grid sites in four countries, is only able to obtain, at best, a 65% error rate in predicting consumer consumption. Using both survey and smart meter data from 1,378 mini-grid connections in Tanzania, Allee et al (2021) show that their best-performing model has a median absolute error of 66% for individual connections and 37% for mini-grid sites. This does not, however, mean that no useful demand analysis is possible. A planner can construct several scenarios to bound the plausible range, and can draw on the general conclusions of the literature – that households in newly electrified rural areas do not always connect, and that those who do tend to consume little and to increase consumption slowly – to improve on estimates derived from current energy expenditure surveys or backed out from policy objectives.

Second, the demand assessment scenarios can be used to derive (i) an estimate of both the connection and consumption subsidies required to meet policy objectives, should a planner decide to pursue them and (ii) an estimate of the impact of the investments on utility and sovereign debt, decomposing direct fiscal risk (resulting from public investments) from contingent fiscal risk (resulting from de-risking instruments).

Our call to explicitly model demand assumptions and make fiscal risk transparent mirrors the broader case for subsidy transparency. The World Bank (2026) argues that the fiscal costs of subsidies – including revenue forgone from non-cost-reflective utility tariffs and contingent liabilities from guarantees – are systematically under-recorded, and that comprehensive accounting is the precondition for reform.

Box 6. When new investment reduces fiscal risk

This paper flags the risks of extending access to new, low-income households, where the revenue to recover new fixed costs may not materialize. Other investments, particularly if they replace older, costly sources of supply, could reduce fiscal risk.

New generation, including renewables, could displace high-marginal-cost, fossil-fuel-based alternatives — in particular the emergency "powerships" deployed across a number of African countries, whose contracts combine a fixed capacity charge with a fuel cost that passes through to the utility. Where this is the case, we fully agree with the logic that concessional investment can be justified: the relevant comparison is not new revenue versus fixed cost, but the lifetime cost of the new asset versus the recurring cost of what it retires. Extension to unelectrified, low-consumption households and replacement of expensive generation for demand that already exists therefore are fundamentally different questions for sovereign fiscal risk — the first adds risk, the second can reduce it. Because generation is the largest investment line in every Compact that discloses one (Table 4), the balance between these two effects is an important question.

Two questions follow: how did fiscally constrained states come to rely on emergency power procured at several times the cost of alternatives, and how can they exit those commitments as new capacity comes online? The answers to these questions are outside the scope of this paper, but are important to understand to avoid reliance on emergency power procurement.

As with the other risks flagged throughout this paper, this belongs in a full budgetary disclosure of each Compact: the goal is to assess the net effect on fiscal risk — new exposure from demand-driven extension versus reduced exposure from retiring costly existing emergency power procurement.

Suggestion 2: Improve reliability and sequence by demand in areas with demonstrated high demand

If connection and consumption are hard to predict in yet-to-be-electrified areas, some areas may have strong, identifiable demand. The suggestion to sequence investment — first to projects with such identified, cost-recoverable demand, then to unelectrified areas with more uncertain demand — follows Opalo (2025) and Blimpo (Afronomics, 2025).

Reliability across sub-Saharan Africa is poor — only 43% of Africans report an electricity supply that works "most" or "all" of the time (Afrobarometer, 2022). Investments to improve reliability can generate high returns for the utility: Cissé (2025) finds an internal rate of return of at least 30% for reliability upgrades in Senegal, driven by increased appliance adoption and consumption among already-connected customers.

Reliability also matters for firms. Outages reduce firm profitability in the short run (Abeberese et al., 2019; Hardy and McCasland, 2021), and longer-run effects may be substantially larger – unreliable electricity discourages firms from investing in the electricity-intensive appliances that drive productivity gains (Fried and Lagakos, 2023). Investing in reliability where demand already exists may generate cost-recovering revenues, strengthen utility balance sheets, and create the financial foundation from which expansion could become sustainable. Notably, high-margin revenue from denser areas may provide a basis for future cross-subsidization of rural households. This phase may also have a stronger commercial logic, making private investment more likely to scale without stringent de-risking tools.

The second phase would extend access to underserved areas, after the utility's financial position has been stabilized. As Blimpo (Afronomics, 2025) suggests, households with low ability to pay could then be reached either through social programs financed by an expanding tax base, or through cross-subsidization.

Suggestion 3: Make new data available to improve knowledge of connection and consumption patterns and what drives them.

Most of the available literature comparing ex-ante estimates of demand to realized demand comes from mini-grids (see Suggestion 1). Access to electricity consumption data for the central grid was historically constrained by human-read post-paid meters, with high non-response rates and decentralized recording. The advent of pre-paid meters¹ means that this data exists and is centralized, but it is held by utilities. Research carried out using utility data – Masselus et al. (2025), Mugenyi et al. (2025) and Fobi et al. (2018), is discussed in Section 3.2. of this note. These studies provide valuable information on consumption trends as grids expand and can be used to bound demand scenarios, as suggested above, but are admittedly limited to specific countries (Kenya and Rwanda) and contexts.

Utilities could make anonymized connection and consumption data available for analysis by internal planners as well as researchers and development partners.

Utility data could help provide more precise data to guide electricity infrastructure planning. First, by understanding to what extent the conclusions from the existing literature – low and slow to rise consumption for newly connected households – hold in other contexts. Second, by estimating the elasticity of demand to changes in tariff levels and structures. Third, by understanding to what extent transformer or feeder level – rather than household-level – characteristics (such as presence of an anchor load, residential/commercial mix, market access, etc.) predict transformer or feeder level demand. This may be more useful for a planner, who may typically make infrastructure decisions at the transformer or feeder level.

Suggestion 4: Explore the use of the modularity of mini-grids to hedge demand uncertainty

The modularity of mini-grids may make this technology well suited to the uncertainty surrounding demand. Unlike grid extension, mini-grids can be sized to a minimal demand level and expanded as load increases, where grid and mini-grids share similar fixed and sunk cost structures, mini-grids offer an opportunity to learn about demand rather than commit the full capital costs of grid infrastructure upfront.

There are certainly costs to a staged approach. A staged increase in mini-grid capacity is more expensive than right-sizing infrastructure from the outset (CrossBoundary, 2019) – right-sizing that, in practice, is rarely achievable because demand is hard to forecast. We do not know much about how households and firms may react to an undersized mini-grid – which may ration connections or lead to unreliable supply. Would potential customers purchase self-generation assets (such as diesel generators or solar systems), and prove complicated to recapture? Would electrical assets bought during mini-grid deployment be resold by disappointed customers? Ensuring that mini-grid operators are able to quickly increase capacity as demand materializes also poses clear financial, regulatory, and logistical – mini-grids are often located in remote areas – challenges. A potential solution is to deploy mini-grids as portfolios rather than individual projects, with rapid access to escrow accounts for sites where demand materializes and pre-approved regulatory processes to increase capacity.

The evidence base on the costs and benefits of a staged approach – as opposed to a single optimization – is thin. There exists, to our knowledge, only one case study – based on two mini-grids in rural India – which finds that a staged approach may lead to cost reductions of around 12% (Sayani et al., 2022). Our call for increasing the evidence base is one for more research rather than direct policy action, and follows Allee et al. (2021): *“Even if utilizing best practices for predicting electricity consumption, mini-grid practitioners should anticipate a range of prediction errors (-80% to +20% across our sites for the LASSO) when designing their systems [...] Further studies should examine the financial value of modular design given the level of demand uncertainty observed in this paper.”*

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