Ministry of Energy

A Financing Roadmap for Zambia's Integrated Resource Plan

2026

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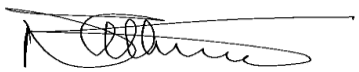
FOREWORD

The Government of the Republic of Zambia has prioritised the development of electricity infrastructure as a backbone for Zambia's economic transformation and social development. Reliable, affordable, and sustainable energy is essential to powering growth across the mining, agriculture, manufacturing and service sectors, while improving livelihoods for households in both urban and rural areas in line with the national target of achieving universal access to electricity by 2030.

In February 2024, the Government launched Zambia's Integrated Resource Plan (IRP), which sets out a least-cost pathway for meeting the country's electricity needs to 2050. The IRP highlights significant opportunities to strengthen energy security by diversifying the energy mix – building on Zambia's hydropower foundation by strategically expanding it in less climate-sensitive locations, while simultaneously broadening the generation base to include solar, wind, geothermal and biomass. Hydropower has historically underpinned Zambia's electricity supply and remains central to the IRP's long-term generation plan. Recent climate-induced droughts, however, have underscored the urgency of ensuring that future investment is both geographically and technologically diversified

Delivering the ambitions set out in the IRP will require unprecedented levels of investment across the electricity value chain. The Government has thus developed a Financing Roadmap for Zambia's IRP to provide a practical bridge between investment planning and implementation by setting out how required capital can be strategically mobilised, allocated and sequenced in line with fiscal and evolving market conditions. The development of the Financing Roadmap was highly inclusive and consultative, engaging over 30 local and international institutions in energy and finance-related fields. The Financing Roadmap is intended to serve as a living document, to be updated as policies, market conditions and the IRP itself evolve.

The Ministry of Energy is committed to working closely with all stakeholders to implement the financing roadmap in order to deliver a resilient, inclusive and financially sustainable power sector that supports Zambia's long-term goals.



Hon. Makozo Chikote, MP
Minister of Energy

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The development of the Financing Roadmap for the Integrated Resource Plan was a comprehensive, iterative process that drew on expertise across power systems, public policy, climate and private finance and economics, among other disciplines.

While it is not possible to mention everyone who contributed to the development of the Financing Roadmap, we would like to acknowledge the contributions from the following institutions:

1. Government Ministries/Institutions;
2. Cooperating Partners;
3. Financial Institutions;
4. Non-Governmental Organisations;
5. Professional Bodies;
6. Energy Consumers;
7. Energy and Power Utilities; and
8. Private Sector

The development and publication of this Financing Roadmap would not have been possible without the financial and technical support from the UK's Foreign, Commonwealth and Development Office (FCDO), through the technical assistance provided by the Climate Compatible Growth (CCG) and Cities and Infrastructure for Growth Zambia (CIGZambia) programmes.

The Ministry of Energy is grateful for the constructive engagement and cooperation demonstrated by all participating institutions.

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Abbreviations and Acronyms

Acronym	Full Term
AF	Adaptation Fund
AUM	Assets Under Management
BAU	Business-As-Usual
CEC	Copperbelt Energy Corporation
CFU	Climate Finance Unit
CIGZ	Cities for Infrastructure Growth Zambia
CoD/CoE	Cost of Debt/Equity
COSS	Cost of Service Study
CPI	Climate Policy Initiative
CSEM	Centre for Sustainable Energy Modelling
D2D	Data-to-Deal
DFI	Development Finance Institute
EIRR	Equity Internal Rate of Return
EMP	Energy Modelling Platform
ERB	Energy Regulation Board
FX	Foreign Exchange
GCF	Green Climate Fund
GCIEP	Green Cities, Infrastructure and Energy Programme
GRZ	Government Republic of Zambia
GWh	Gigawatt Hour
IMF	International Monetary Fund
IPP	Independent Power Purchaser
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
ISMO	Independent System & Market Operator
kWh	Kilowatt Hour
LCGEP	Least-Cost Geospatial Electrification Plan
L.F.	Load Factor
MINFin	Model for Informed National Finance
MoE	Ministry of Energy
MoFNP	Ministry of Finance and National Planning
MoGEE	Ministry of Green Economy and Environment
MW	Mega Watt
MYT	Multi-Year Tariffs
NAP	National Adaptation Plan
NDC	Nationally Determined Contribution

Acronym	Full Term
PPA	Power Purchase Agreement
PPP	Public-Private Partnerships
PST	Public Service Trader
PUE	Productive Uses of Energy
RBF	Results-based financing
REA	Rural Electrification Authority
REMP	Rural Electrification Master Plan
RMI	Risk Mitigation Instruments
SAPP	Southern African Power Pool
SEforALL	Sustainable Energy for All
S.I.	Statutory Instrument
SP	Strategic Principle
TA	Technical Assistance
WACC	Weighted Average Cost of Capital
ZMW	Zambian Kwacha

Executive Summary

Situation Analysis

Zambia is advancing reforms to its market power while strengthening the resilience of its power system to climate change. The 2023 Integrated Resource Plan (IRP) outlines a least-cost pathway to expand its power market to meet growing demand and transition toward a diversified energy mix [1]. This includes reducing reliance on hydropower in southern Zambia, which is increasingly vulnerable to prolonged drought. The plan estimates a cumulative investment requirement of $11.6 billion by 2030, escalating to $31 billion by 2050. In parallel, the Open Access Framework (2025) shifts the market from a perceived Single Buyer Model toward a “willing buyer, willing seller” regime [2] This allows independent power producers (IPPs) to sign contracts directly with large energy customers, thereby expanding opportunities for private-sector investment.

While the IRP outlines the necessary investments, it offers less guidance on how they will be financed. To address this gap, Climate Compatible Growth (CCG), with technical support from Cities for Infrastructure Growth Zambia (CIGZ) and Kukula Capital, has been engaged by the Ministry of Energy to develop a financing roadmap to facilitate the implementation of the IRP.

Objective

The overarching objective of the Financing Roadmap is to guide the mobilisation and use of concessional, domestic, and commercial capital across the long-term IRP investment pipeline to ensure:

- Power projects are financially viable;
- Public finances remain sustainable; and
- Costs are fairly shared among consumer groups.

The analysis assesses the financial feasibility of the IRP at both the project and system levels and provides a practical roadmap for delivering it at scale.

- System-wide feasibility*:* Examines total IRP financing needs relative to the cashflows projected sector cashflows. A ‘financing gap’ occurs when sectoral cash flows are insufficient to cover total financing requirements.
- Project-level feasibility*:* Examines IRP power project archetypes reflecting typical characteristics in Zambia to determine whether they can generate sufficient revenue to cover debt and provide reasonable returns to equity investors.

Key Findings and Recommendations

Historic approaches to investment finance are not sufficient for the IRP

Sustaining a historic reliance on highly concessional finance is insufficient for the IRP given the ambitious scale of investment and the constrained availability of concessional finance. Historically, low-interest loans from bilateral and multilateral development banks have provided nearly half of sector financing, averaging around US$231m per year. This falls well short of the US$1.07bn in annual investment needed under the IRP. As concessional finance is unlikely to scale to this level, long-term IRP investments will need to rely more on private sector participation, with concessional finance used strategically to leverage larger volumes of private capital.

Historic reliance on the perceived Single Buyer Model also presents challenges for IRP financing. Under this model, all IRP investment costs are passed through to the public utility to be recovered through end-user tariffs. This exposes IRP investments to creditworthiness challenges in the public utility sector, raising risks and reducing project bankability. In addition, about half of Zambia's power is consumed by the mining sector and billed in dollars, with the remaining half billed in local currency. Reliance on this model prevents investors from directly accessing dollar revenue streams, thereby reducing exposure to foreign exchange risk and improving bankability.

Adoption of the Open Access Framework presents new financing opportunities

Under Open Access, some projects will be contracted directly to large energy consumers, and others will be delivered through the national utility as the Public Service Trader (PST). This arrangement allows a significant portion of IRP projects to benefit from the strong credit profiles and dollar-based revenues associated with large energy consumers. This improves investor confidence and supports greater access to the much larger volumes of international commercial capital that would be needed to finance the ambition associated with the IRP.

While Open Access may facilitate financing of the IRP in the near term, the transition introduces longer-term considerations for the PST. Although direct contracting of IRP investments by large energy consumers could significantly lower public financing costs, an increasing share of foreign-currency revenues may bypass the public system as these consumers shift toward bilateral arrangements, potentially increasing foreign exchange exposure over time. Financial modelling suggests that these pressures could become salient by the mid-2030s, if no mitigating measures are introduced.

However, large energy consumers would likely continue to rely on the PST for system balancing and backup supply. This ongoing system interdependence provides an opportunity for compensating mechanisms that maintain fair cost-sharing across consumer groups while supporting the long-term sustainability of the power sector.

Strategic use of limited concessional and domestic financing can maximise leverage of international commercial capital

To meet the substantial financing needs of the IRP, it is important to strategically allocate limited concessional and domestic financing envelopes to maximise leverage of international commercial capital. It is estimated that Zambia could potentially access some US$279m in international concessional finance annually, plus some US$77m in domestic commercial finance annually. International concessional finance is particularly valuable for its relatively soft financing terms and long loan tenors. Domestic commercial finance is additionally helpful because it avoids exposure to foreign exchange risk. Given that both sources of finance are limited, it is important to deploy them as efficiently as possible to maximise the leverage of international commercial finance (est. US$369m needed annually), which has greater potential to scale.

Concessional resources should be prioritised for early-stage project preparation and PST-offtake projects where they have the most impact. To help meet the US$23.1m annual resource requirement for IRP project preparation, efforts to mobilise concessional finance should target the US$4.71m available each year for this purpose. Meanwhile, investment-stage concessional finance should be prioritised for PST-offtake projects as liquidity and viability support, which helps to strengthen investor confidence and ensure that fiscal exposure remains contained within prudent limits.

Zambia's position to mobilise additional concessional finance can be increased by strengthening local capacity for project preparation, fund applications, and compliance with eligibility criteria. The forthcoming Climate Finance Unit (CFU) is well-positioned to serve as the centralised hub for expanding access to international concessional and climate finance and matching them to suitable projects in the pipeline. In the near term, the unit should target larger-scale, more accessible climate finance windows while progressively pursuing windows with more demanding eligibility criteria as capacity improves. In particular, it should prioritise alignment with the six key eligibility criteria that unlock the majority of concessional finance: Effective Project Management, Gender and Social Inclusion, Evidence of Feasibility Studies, Low Debt Risk, Policy Alignment, and Climate Mitigation/Adaptation.

Given the IRP's strong focus on climate resilience, Zambia is also well positioned to access concessional resources earmarked for climate adaptation. The estimated IRP 'adaptation cost premium' relative to a business-as-usual pathway, equivalent to US$7bn across the life of the IRP or US$152m annually, provides a clear basis for targeting adaptation-focused finance to support IRP power sector investments.

Some policy measures may be needed to direct domestic commercial capital to where it can most effectively support overall IRP financing needs. Given the comparative advantage of domestic markets in providing local-currency finance, these resources could play an important role in reducing foreign-exchange risk for projects with local-currency revenues and limited access to concessional financing, notably those underwritten by the PST. Nevertheless, it is possible that domestic investors may gravitate toward competitive-market projects, given their preference for lower-risk investments.

Greater participation by domestic financial institutions could be supported through targeted fiscal incentives and strengthened capacity to evaluate and manage power-sector project risks. While domestic capital markets currently play a limited role in financing energy infrastructure, stakeholder consultations indicate significant potential for increased participation over the life of the IRP. Carefully designed fiscal instruments, alongside enhanced institutional capacity for project risk assessment, could help strengthen investor confidence and mobilise additional domestic financing for critical energy investments.

Tariff reform is needed to ensure fairness and full cost recovery

Zambia has historically maintained electricity tariffs below the cost of supply, with the government supporting the gap. This approach was viable when production costs were low due to inexpensive hydropower, but it became untenable starting from the 2019 power crisis, when the national utility was compelled to import electricity at prices far above its selling rate [3].

The 2023-2027 Multi-Year Tariffs Framework (MYTF) does not fully account for IRP investment needs [4]. Designed using lower-cost assumptions from the 2019 Cost of Service Study (COSS), the MYTF does not account for the significantly higher investment requirements under the IRP [5]. While the MYTF provides for annual reviews and tariff adjustments based on economic fundamentals, depreciation of the kwacha has outpaced the framework's assumptions, with annual adjustments unable to keep pace with exchange rate movements.

Zambia's electricity market is characterised by a dual structure that drives significant cross-subsidisation. Domestic consumers face affordability constraints and therefore pay low, kwacha-denominated tariffs, while mining and export customers are able and willing to pay higher, foreign-denominated prices for reliable supply. This structure allows higher-value foreign-denominated revenues to partially offset shortfalls from domestic segments, though the sector as a whole remains far from cost-reflective.

The transition to Open Access will require prudent measures to maintain fair cost-sharing. The strategic use of limited concessional and domestic capital significantly reduces financing costs and improves the sector's near-term financial balance. Nevertheless, as large energy customers shift toward competitive supply arrangements, the PST's revenue base risks greater exposure to foreign exchange volatility, necessitating compensating responses. Regulators should consider the possibility of increasing current tariffs in the range of 4-8% per year after 2027 (in nominal terms), as well as increasing current wheeling costs, capacity fees, and other use-of-system costs to ensure that competitive users who continue to depend on the public network contribute to full-system cost recovery. These measures should safeguard sector sustainability without undermining market competitiveness.

1. Introduction

1.1 Situation Analysis

Zambia's first Integrated Resource Plan (IRP) sets out an ambitious roadmap to 2050 for meeting rising electricity demand and building resilience to climate change, but its successful implementation depends on addressing significant financing and institutional constraints. With hydropower supplying over 80% of total installed capacity, the system remains highly vulnerable to droughts – events that are intensifying as a result of climate change, as demonstrated during the 2023-2024 El Niño. In response, the Government of Zambia (GRZ) has prioritised diversifying the national energy mix with technologies such as solar, wind, geothermal, biomass, and coal to meet an anticipated 350% increase in demand by 2050 from 2020 levels [1].

Delivering the IRP will require investment at a scale that far exceeds historic financing levels. IRP investment requirements are expected to reach a cumulative total of US$11.6 billion by 2030, rising to US$31 billion by 2050. This far exceeds the approximately US$7.7 billion in committed finance for energy projects between 2010 and 2024. Almost half of the past power sector financing has come from concessional sources. However, this level of concessional reliance will not be feasible at the scale required under the IRP, particularly in a context of constrained and declining international aid flows. Meeting these needs will therefore require a major expansion of both domestic and international financing sources, with concessional finance used to leverage rather than replace capital.

Zambia's capacity to mobilise finance is currently constrained by the financial position of its national utility as well as wider macroeconomic challenges. Persistent droughts in the last decade have plunged the national utility into financial distress, driven by costly power imports, macroeconomic shocks, and non-cost-reflective tariffs. Zambia's 2021 sovereign default and debt restructuring under the IMF's Extended Credit Facility further limited the government's ability to provide traditional payment security, making it difficult for new projects to reach financial close [6].

The roadmap is being developed during a period of significant market transition, which fundamentally reshapes how risks, revenues, and investment incentives are structured. The sector is shifting from the historic perceived Single Buyer Model (SBM), in which the national utility acted as the sole off-taker, toward a liberalised Open Access Framework (OAF) that allows large consumers to contract directly from Independent Power Producers (IPPs). This transition has major implications for sector financing, cost allocation, and long-term system planning – all of which are addressed in this financing roadmap.

While the IRP sets out the least-cost pathway for Zambia's power system to 2050, it provides less guidance on how the required investment will be financed. This report addresses this gap by assessing the financial feasibility of the IRP at both the project and system levels, taking into account financial and fiscal constraints, and sets out a practical roadmap for delivering it at scale. It identifies potential sources of concessional finance and recommends how these can be strategically allocated across the portfolio of projects to maximise catalytic impact. It also analyses tariff requirements to balance cost recovery with social equity across consumer segments. Crucially, the approach focuses not only on attracting capital, but on structuring and sequencing investments in a manner that safeguards macroeconomic and debt sustainability, thereby creating the conditions necessary to mobilise private investment at scale.

1.2 Vision Statement

To attain the sustainable and financially viable implementation of Zambia's Integrated Resource Plan, with a resilient, diversified, and affordable power system that supports long-term economic growth and macroeconomic stability for all.

1.3 Mission Statement

To develop a financing and implementation roadmap that guides the mobilisation and deployment of concessional, domestic, and commercial capital in a manner that ensures system-wide bankability, safeguards fiscal sustainability, and delivers equitable cost recovery across consumer segments.

1.4 Guiding Principles

The guiding principles on which this Financing Roadmap is anchored align with key national and regional development goals. These key principles underpin the design and implementation of the roadmap and support its overall effectiveness:

1. **Fiscal and Macroeconomic Sustainability**
   The roadmap ensures that IRP implementation remains consistent with Zambia's long-term debt sustainability framework. Recommended financing structures are designed to minimise fiscal risk and prevent the accumulation of unsustainable contingent liabilities.

2. **System-Wide Viability and Scalability**
   The roadmap promotes financing solutions that are viable across the full IRP pipeline, rather than concentrated in a limited number of flagship projects. It achieves this by outlining how scarce and constrained concessional and domestic resources can be deployed strategically across IRP technologies to maximise the leverage of international commercial finance, which has greater potential to scale.

3. **Consideration for Social Equity**
   The roadmap considers social equity as central to the socialisation of IRP costs across consumer groups. Tariff structures and cost allocation mechanisms are designed to balance financial recovery with affordability, protecting vulnerable consumers and supporting universal electricity access goals.

4. **Transparency and Evidence-Based Decision-Making**
   The roadmap's findings and recommendations are grounded in transparent and replicable analytical methods and stakeholder-validated assumptions to support accountable and evidence-based decision-making.

1.5 Objectives of the Financing Roadmap

The overarching objective of the Financing Roadmap is to guide the mobilisation and deployment of concessional, domestic, and commercial capital for IRP investments in a manner that ensures system-wide bankability, safeguards fiscal sustainability, and delivers equitable cost recovery across consumer segments.

The three specific objectives of the analysis are:

1. *Assess sector-wide financial implications of IRP implementation to 2050,* including affordability, debt implications, and other key fiscal considerations related to the transition.
2. *Determine optimal tariff pathways and allocation of concessional and domestic finance* across IRP technologies to maximise project and plan-level bankability.
3. *Develop strategic principles and policy actions* to bridge the sector- and project-level financing gaps.

1.6 Scope and Approach

The IRP Financing Roadmap aligns with the Data-to-Deal (D2D) Framework. The term 'Data-to-Deal' refers to action along an entire pipeline that runs from data collection, system modelling, and development planning, all the way through to national financing strategies and project finance arrangements, all driven by a strong stakeholder engagement process [7]. In this case, the objective is to progress from Component 4, in which the IRP serves as the development plan, generated through deliberative modelling, to Component 7, where a finance strategy is developed (Figure 1). Throughout this process, every step is supported by inclusive stakeholder engagement and local ownership.

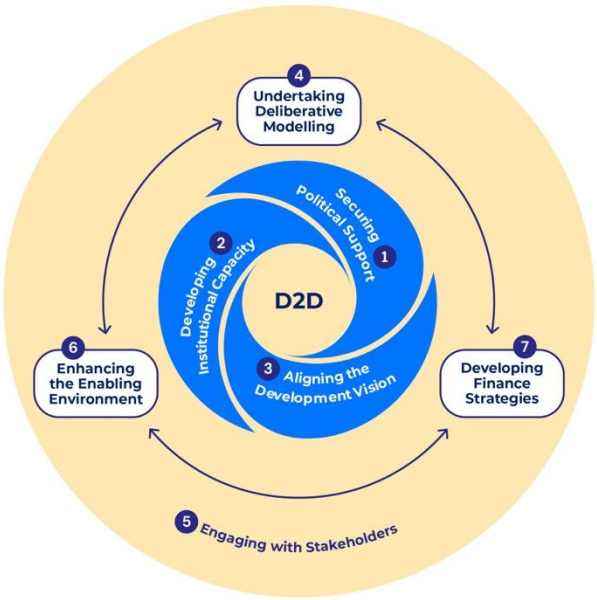

Figure 1. The Data-to-Deal (D2D) Framework.

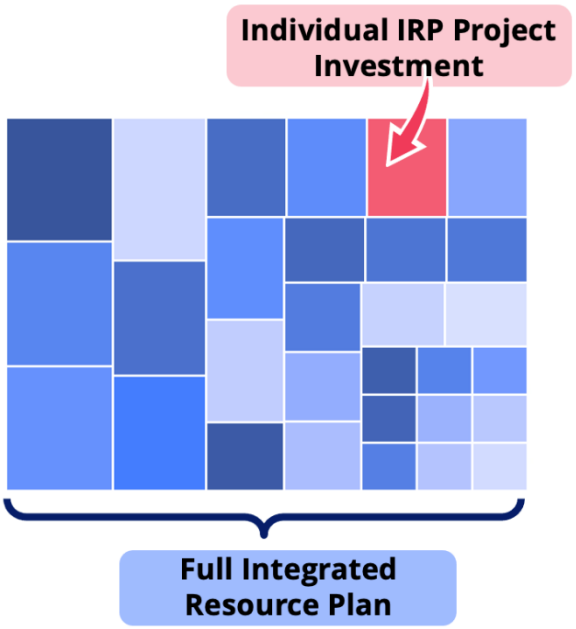

Figure 2. Two-Level Analysis Approach.

This report assesses the financial feasibility of the IRP at both the project and system levels and sets out a practical roadmap for delivering it at scale (Figure 2). Financing discussions often centre on single projects, not the bigger challenge of financing the whole plan. While individual projects can be made bankable with enough concessional finance or risk mitigation measures, these solutions are often not scalable across the entire pipeline.

The analysis focuses on grid and grid-connected IRP technologies. While Section 5 presents a separate analysis for the mini-grid sector, the rest of the report remains limited to grid and grid-connected IRP technologies, in line with the IRP's focus.

Key recommendations emerging from the analysis are organised into two interacting categories:

1. **Strategic Principles (SP):** These represent broader, high-level strategies that guide overall decision-making and policy development. SPs are informed by the analysis and provide a foundational rationale for the actions taken by institutional actors.
2. **Policy Actions (PA):** These are specific, actionable steps that can be implemented by particular institutional actors. Each PA is designed to advance the objectives set forth by the corresponding SP, with clear justifications provided by the broader analysis.

The report is structured as follows:

- **Section 1** sets the context for the Financing Roadmap, outlining the situational context of Zambia's power sector, defining the vision, guiding principles and objectives of the analysis.
- **Section 2** provides background and context for Zambia's energy sector and ongoing market reform agenda.
- **Section 3** presents the estimated IRP financing gap under both continuation of the perceived Single Buyer Model and the transition toward Open Access, assuming fully commercial financing terms.
- **Section 4** sets out the strategic financing recommendations and suggested policy actions to bridge the financing gap, organised under two pillars:
    - **Pillar 1:** Strategic Mobilisation and Deployment of Concessional Finance and Domestic Commercial Capital
    - **Pillar 2:** Tariff Reform for Fairness and Cost-Recovery
- **Section 5** provides targeted financing recommendations and policy actions for the mini-grid sector.
- **Section 6** summarises key strategic principles and policy actions across Sections 5 and 6 and maps them to responsible institutional actors.
- **Section 7** concludes with main takeaways and outlines proposed next steps.

2. Background and Context

2.1 Zambia's Generation Mix

Zambia's power sector is highly vulnerable to climate shocks due to its dependence on hydropower, which supplies over 80% of electricity. Recent El Niño cycles, intensified by climate change, have brought longer and more severe droughts that have sharply reduced hydropower output. This resulted in persistent loadshedding of up to 21 hours at its peak, constraining productivity and slowing economic growth.

The IRP outlines a least-cost pathway for expanding and diversifying Zambia's generation mix to strengthen resilience to climate shocks and meet rising demand. As Figure 3 shows, it anticipates a five-fold increase in total installed capacity by 2050 from 2023 levels, with a growing shift toward solar, wind, geothermal, biomass, coal, and geographically diversified hydropower in the Northeast, which is less susceptible to drought. However, the IRP is agnostic about how this capacity will be owned or delivered.

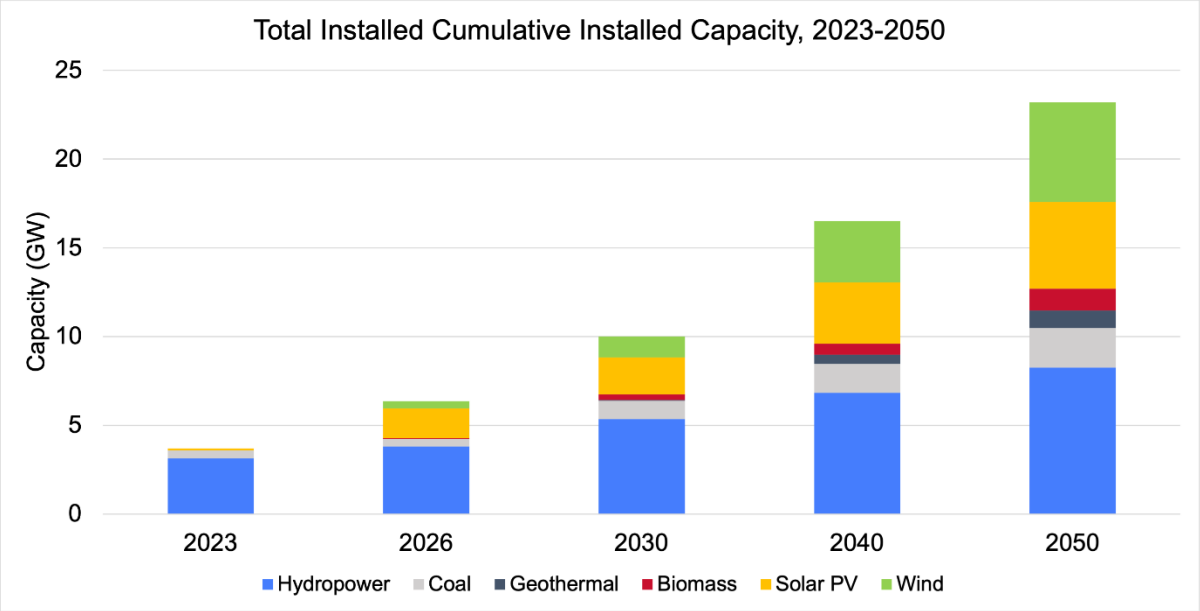

Figure 3. Total Cumulative Installed Capacity from the IRP, 2023-2050.

2.2 Zambia's Power Sector Under the Perceived Single Buyer Model

Zambia's power sector has historically operated under a perceived Single Buyer Model, with the vertically integrated national utility serving as the sole off-taker. The Copperbelt Energy Corporation (CEC) is the largest private-sector player in the transmission subsector, supplying most mining operations in the Copperbelt. Although CEC owns generation facilities, it primarily sources power from the national utility through a Bulk Supply Agreement. In the generation sub-sector, a growing number of Independent Power Producers (IPPs) have entered the market in recent years, selling electricity to the national utility under long-term Power Purchase Agreements (PPAs). Zambia is also interconnected with the Southern African Power Pool (SAPP), enabling cross-border power trade with neighbouring countries.

Costly emergency power imports during the droughts have pushed the national utility into financial distress. Combined with non-cost-reflective tariffs and sharp local currency depreciation, the national utility has plunged into a negative financial position. In 2024 alone, loadshedding led to an estimated US$300 million in lost revenue over just four months [8]. This drove the utility to issue an emergency tariff adjustment for its residential, commercial, and maximum-demand consumers for the full year, from October 2024 to October 2025, which was approved and issued by the ERB [9].

GRZ's reduced fiscal capacity has limited its ability to support the national utility through guarantees (Figure 4). Before Zambia's 2021 sovereign debt default, the national utility relied on public resources to cover the gap created by non-cost-reflective tariffs amongst domestic consumers. However, a series of shocks to the economy has constrained government spending, reducing confidence in the sector and creating a challenging environment for energy sector investment.

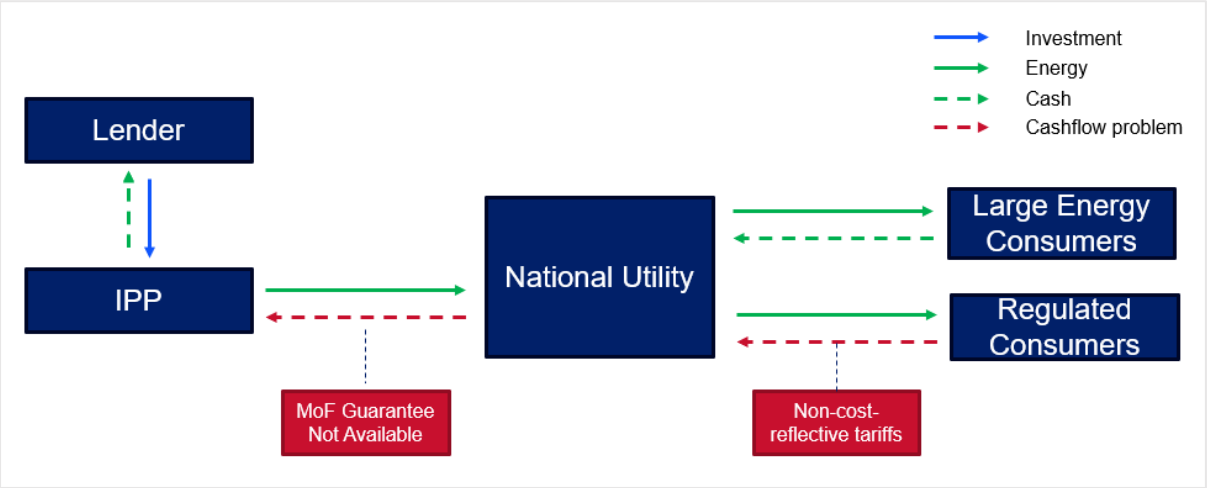

Figure 4. Cashflow Risks in Zambia's Power Market Under the Perceived Single Buyer Model, Post-Macroeconomic Crisis.

GRZ's commitments under the IMF's restructuring programme restrict the use of sovereign credit support and limit external borrowing to concessional sources. Under the 38-month Extended Credit Facility, many of the standard risk-mitigation instruments that normally underpin bankable PPAs when a state utility is financially distressed are no longer available [10], [11], [12]. Overcoming these constraints will require a combination of market restructuring, tariff reform, and strategic mobilisation and allocation of finance across both project lifecycles and investment pipelines.

2.3 Ongoing Market Transition Toward Open Access

The Open Access Framework is designed to enhance private-sector participation and boost investment in new energy projects. Under this framework, large consumers can enter direct bilateral contracts with IPPs and access the national grid on a non-discriminatory basis [2]. By shifting away from relying on the national utility as the sole off-taker towards a more liberalised "willing buyer, willing seller" regime, the framework helps de-risk projects and improve revenue certainty, making the sector more attractive to investors.

Even under a liberalised market, the national utility will continue to fulfil its public service mandate through a ringfenced unit called the Public Service Trader (PST), which will be responsible three essential functions:

1. *Supplying customers who are unable to participate in the open market*.

2. *Providing system stability*, drawing on its operational capacity to manage increasing market complexity as variable renewable energy and multiple off-takers enter the system.
3. *Addressing both current and future energy shortages* to maintain overall energy security.

An Independent System and Market Operator (ISMO) will operate across the dual-track market (Figure 5). The ISMO will be responsible for the System Operator license, ensuring system stability across the competitive and regulated market tracks. Meanwhile, the Energy Regulation Board is developing a transparent transmission and distribution pricing methodology to support fair network access and cost recovery [13].

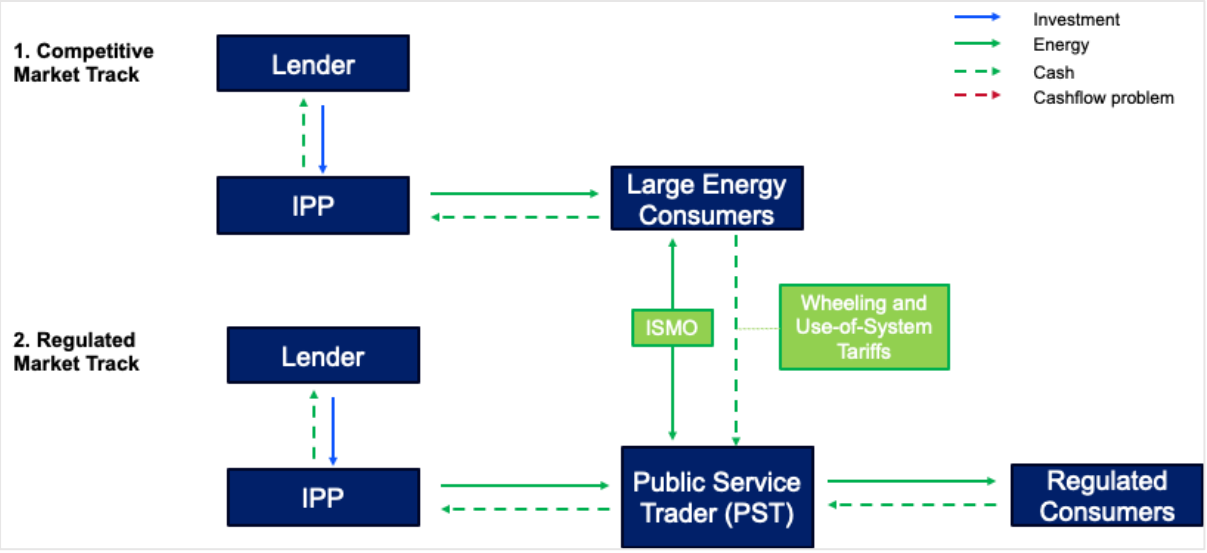

Figure 5. Zambia's Power Market Under the Open Access Framework.

A well-structured tariff framework and the strategic use of financial resources will be key to ensuring that the national utility fulfils its mandate. Under Open Access, sustaining system-wide cost recovery becomes more challenging as services are unbundled and higher-paying consumers move to the competitive market, increasing the concentration of offtake, revenue, and currency risks in the regulated market. Ensuring that the national utility can secure the financing required to diversify its generation portfolio will therefore require a fair, well-designed approach to cost socialisation and the effective deployment of limited financial resources across both tracks. The remainder of this report examines these solutions in detail.

3. Initial Diagnosis of the IRP Financing Gap

This section diagnoses the estimated IRP financing gap and assesses the financial implications of the market transition. By comparing the financing gap under the continuation of the perceived Single Buyer Model with that under the transition to Open Access, the potential financial impacts of this shift can be more clearly understood. This initial diagnosis assumes the IRP is fully financed through international commercial finance, with no changes in current tariff levels. While these assumptions can be viewed as challenging, they provide a useful upper-bound baseline estimate of the financing gap, helping to identify subsequent funding and financing strategies and assess their effectiveness.

3.1 Defining a Financing Gap at Sector and Project Levels

MINFin provides a top-down overview of the financial feasibility of a country's energy plan. The Model for Informed National Finance (MINFin) is a national finance planning model which takes the upfront investment costs associated with a country's long-term investment plan (in this case, the IRP), computes the associated financing costs, and compares them to available cashflows over the same period [14]. Where annual cashflows are inadequate to service annual financing obligations, a sector-wide "financing gap" is said to occur.

OSeMOSYS quantifies the average annual upfront investment needed to implement the IRP at US$1.07bn to 2050. The Open-Source Energy Modelling System (OSeMOSYS) was used to provide an annual breakdown of IRP investment needs by technology, as displayed in Figure 6. The upfront investment spike arises because expenditures planned for 2023-2026 are now concentrated in the near term.

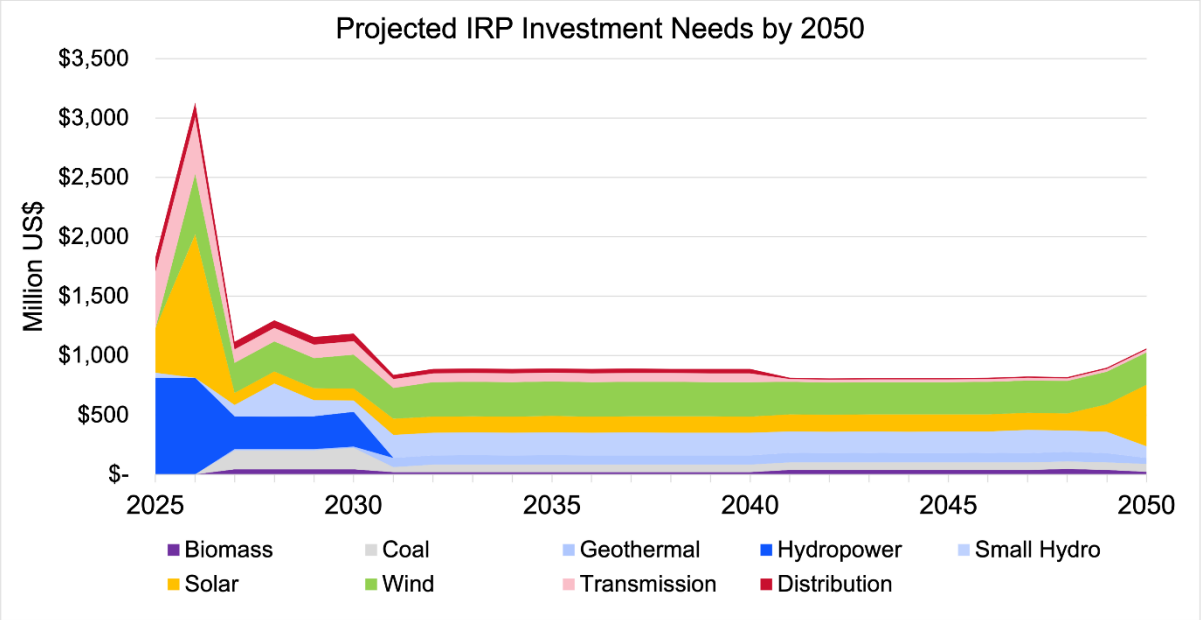

Figure 6. Projected IRP Investment Needs by Technology, 2025-2050 (OSeMOSYS).

To evaluate project-level bankability, IRP investments are broken down into seven generation project archetypes reflecting typical sizes and characteristics in Zambia. Table 1 summarises the capacity and costs of these project archetypes and their associated share of total IRP capacity additions and investments. The sector-level picture can be derived by reaggregating individual projects based on their weights.

Table 1. IRP Generation Project Archetypes: Assumptions and Associated Investment Weights.

IRP Project Archetype	Capacity (MW)	Capital Cost (US$M/MW)	Share of Total Capacity Addition by 2050 (%)	Share of IRP Generation Investments 2026-2030 (%)	Share of IRP Generation Investments 2031-2050 (%)
Hydro - Large	250	1.28	36%	39%	24%
Hydro - Small	20				
Wind	100	1.29	24%	21%	36%
Solar PV	100	1.01	21%	27%	18%
Coal	300	1.07	10%	9%	8%
Biomass	50	0.63	5%	3%	4%
Geothermal	20	1.60	4%	1%	10%

The bankable Power Purchase Agreement (PPA) price is derived from ensuring that a project's equity return meets investors' expectations.[1] Revenues generated through end-user tariffs must be sufficient to cover the contracted generation at this price, with any remaining cashflows available to address the IRP's financing needs.

These two levels are interdependent, which MINFin addresses together. A plan cannot be delivered if projects within it are not bankable, and individual bankable projects cannot scale without a financially viable sector.

3.2 Financing Gap Under the Historic Perceived Single Buyer Model

Sustaining a historic reliance on highly concessional finance for IRP investments is infeasible given existing resource constraints. Past energy projects reaching financial close between 2010-2024 heavily relied on concessional financing on average, with 44.5% of total financing sourced from bilateral and multilateral agencies, including China. These agencies offered substantially favourable terms, with average interest rates of 5.8%, loan tenors of 20.9 years, and grace periods of 3.5 years. However, only US$7.9bn of total financing was mobilised for power projects across 2010-2014, starkly contrasting with the nearly US$28bn needed for upfront IRP investments from 2025 to 2050. This represents a significant and rapid scaling-up of investment relative to historic levels.

Future financing terms are expected to align more closely with market conditions, with concessional finance used primarily to leverage rather than replace private investment. Assuming the IRP is financed entirely through international commercial capital, the annual financing requirement is estimated at US$1.4bn through 2050 (Figure 7). This premium is attributed to the high financing costs associated with investing in Zambia, where interest rates are expected to range from 19.48%-24.14%, with an assumed loan tenor of 15 years and no grace period.

[1] A project is considered bankable when its expected return, measured by the Equity Internal Rate of Return (EIRR), meets or exceeds an estimated benchmark Cost of Equity (CoE). Because equity investors are the last to be repaid, meeting this benchmark indicates the project can also satisfy lenders and other financiers, signalling overall bankability.

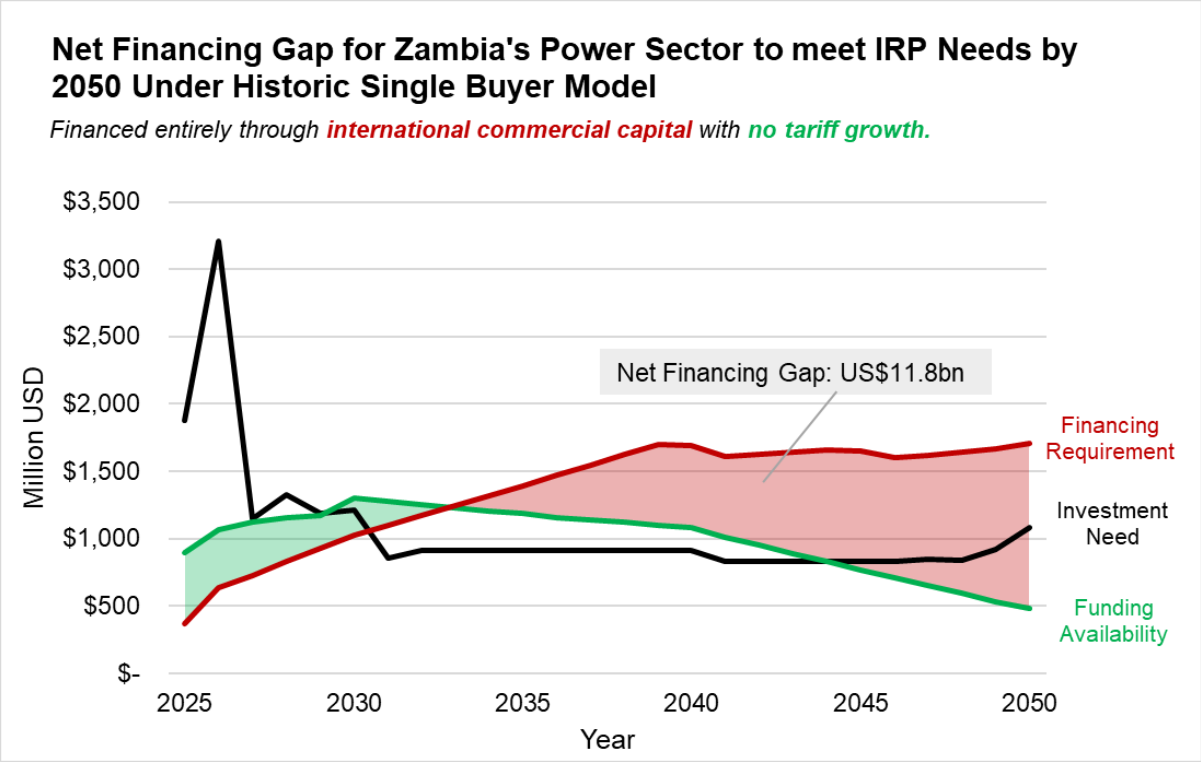

Figure 7. IRP Financing Gap Under Fully Commercial Terms and Perceived Single Buyer Model, 2025-2050 (MINFin).

Under the continuation of the perceived Single Buyer Model, all IRP investment costs are passed through to the national utility, which must recover these costs through end-user tariffs. However, a significant portion of the national utility customers is billed in local currency, while financing costs and IPP purchases are denominated in foreign currency. This disparity diminishes the real value of cashflows over time as inflation and currency depreciation erode the purchasing power of local revenues.

Thus, cashflows generated under current tariffs fall short of required financing after 2035, resulting in a net financing gap of US$11.8bn between 2025 and 2050. As shown in Figure 7, although cashflows are projected to be sufficient to cover estimated financing needs in the first few years of the IRP, a financing gap emerges after 2032 [15]. As additional projects are rolled out, financing repayments begin to accumulate and the effect of currency depreciation compounds, leading the annual financing gap to widen from US$18.4m in 2033 to almost US$1.3bn in 2050.

3.3 Financing Gap Under the Transition to Open Access

Under Open Access, a growing portion of generation investments is expected to be financed through direct contracting with large energy consumers, while the remainder continues to be delivered through the national utility in its role as Public Service Trader (PST). This arrangement could enhance project bankability by enabling certain investments to benefit from the stronger credit profiles and dollar-based revenues of large industrial customers, potentially unlocking higher volumes of international commercial financing required to support the ambitions of the IRP.

Diversification of financing pathways allows a portion of IRP investments to be delivered outside the national utility's balance sheet, reducing its direct investment burden. As shown in Figure 8, annual investment needs decrease from US$1.07bn under Single Buyer to only US$642m under Open Access.

Despite lower investment requirements, the net financing gap could soar to US$23.1bn due to expected weaker net cashflows. As large consumers contribute less to the national utility's revenue base under Open Access, its repayment capacity becomes increasingly constrained and exposed to foreign exchange volatility. Figure 8 indicates that, without any tariff increase or appropriate financial safeguards that maintain historic cross-subsidisation, the national utility's cashflows could deteriorate significantly, potentially falling to below zero by 2037.

However, large energy consumers would likely continue to rely on the PST for system balancing and backup supply. This ongoing system interdependence creates an opportunity for compensating mechanisms that maintain some level of cross-subsidisation between consumer groups.

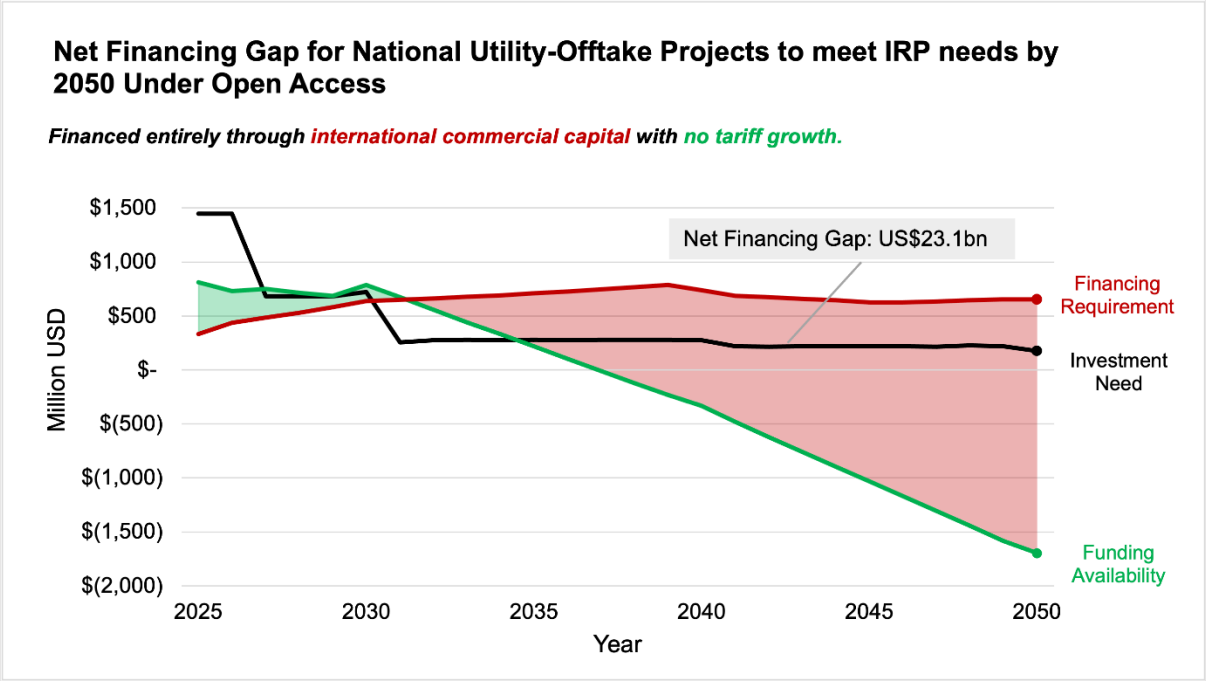

Figure 8. IRP Financing Gap Under Fully Commercial Terms and Transition to Open Access, 2025-2050 (MINFin).

The next chapter sets out the strategies and policies designed to reduce the financing requirement and enhance funding availability, thereby effectively bridging the financing gap.

4. Strategic Principles and Policy Actions to Bridge the IRP Financing Gap

This chapter outlines the strategic principles and policy actions required to bridge the estimated financing gap under Open Access. This is achieved through two key pillars, summarised in Table 2.

Table 2. Summary of Two Key Pillars for Closing the IRP Financing Gap, their Mechanisms and Intended Impacts.

Pillar	Mechanism	Intended Impact
1. **Strategic Mobilisation and Deployment of Concessional Finance and Domestic Capital**	Lowers weighted average costs of capital (WACC) and forex exposure, thereby reducing sectoral financing costs.	↓ **Financing Requirement**
2. **Tariff Reform for Fairness and Cost-Recovery**	Increases sectoral cashflows.	↑ **Funding Availability**

4.1 Pillar 1: Strategic Mobilisation and Deployment of Concessional Finance and Domestic Commercial Finance

4.1.1 Background on Key Financing Types

Almost half of Zambia's past power sector financing has come from concessional sources, but this will not be feasible at the much larger investment scale required under the IRP. Historically, low-interest loans from bilateral and multilateral development banks have provided nearly half of sector financing, averaging around US$231m per year. This falls far short of the US$1.07bn of investment needed annually under the IRP. As Zambia's increasing demand for energy finance coincides with a period of constrained and declining international aid flows, IRP investments will need to rely more on private sector financing, with concessional finance used to leverage rather than replace private capital.

To meet the substantial financing needs of the IRP, the sector will need to effectively mobilise and strategically blend a combination of international commercial finance, international concessional finance, and domestic commercial finance. While international commercial finance is theoretically unlimited, it is typically more expensive and harder to mobilise, particularly if confidence among investors is low. By contrast, international concessional and domestic commercial finance offer more favourable terms or protection against foreign exchange risks but are both highly constrained in availability.

Table 3 summarises the estimated availability of each source, along with their distinctive advantages and challenges. This is followed by a more detailed look at international concessional and domestic commercial sources of finance, respectively.

Table 3. Summary of Key Financing Sources and Characteristics.

Financing Source	Est. Annual Availability	Indicative WACCs[2]	Key Advantages	Key Challenges
International Commercial	Theoretically unlimited	14-22%	• Large potential capital pool • Fast disbursement	• Difficult to attract investors • High cost of capital • Forex risk exposure
International Concessional	US$507m (incl. **US$279m** for energy sector)	0-9%	• Favourable terms • Long tenors	• Limited availability • High barriers to access • Complex, slow disbursement process • Forex risk exposure
Domestic Commercial	**US$76.9m**	20-26%	• Reduces forex exposure risk • Supports local ownership	• Limited availability • High cost of local capital

1. Concessional Finance

FinTrack provides an overview of concessional resources that may be available for Zambia going forward. By tracking current allocations across 33 major climate and development funds, FinTrack offers insight into potential future availability, historical utilisation, and the criteria countries must meet to access these resources [15]. This makes it a useful tool for identifying opportunities for accessing additional concessional resources to address Zambia's IRP financing gap. The full list of funds assessed can be found in the Appendix.

Zambia is well-positioned to mobilise additional concessional climate finance under existing global commitments. According to FinTrack, approximately US$ 507.3m of concessional climate finance is available annually to Zambia across all sectors. Assuming around 55% of available concessional finance is directed to the energy sector,[3] around US$279m of concessional climate finance per year could potentially be mobilised to support IRP-related investments. As shown in

Figure 9, the majority of this financing (80%) is expected to come from development funds, while the remaining 20% is channelled through climate finance windows.

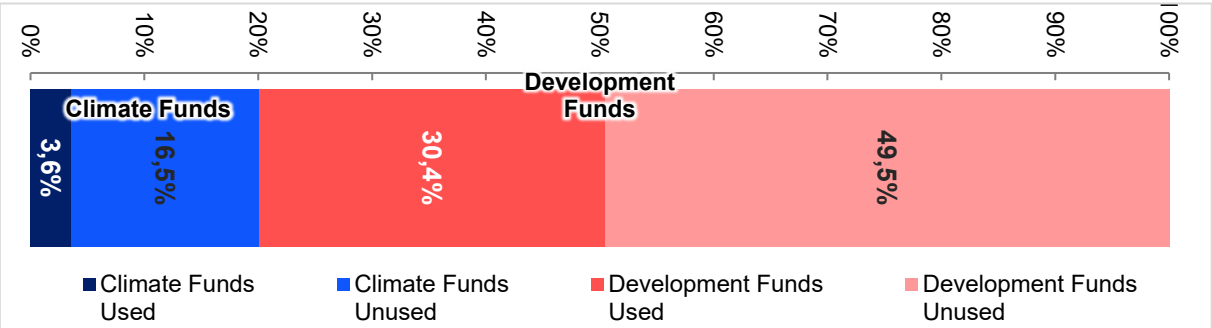

Figure 9. Share of Climate Fund Annual Allocation & Use in Zambia (FinTrack).

[2] WACCs for international and domestic Commercial finance were estimated based largely on the FinCoRE methodology, accessible here: https://wacc-forecaster.streamlit.app/ [35] Costs of debt estimates for concessional finance were provided in FinTrack.

[3] Assumption based on overall trends observed across Southern Africa and on the continent, indicating that the majority of climate finance is allocated to the energy sector [10], [11], [12]

There is significant scope to further leverage US$332.8m of previously untapped concessional finance to support IRP-related investments. Realising this opportunity, however, depends on meeting a range of technical, institutional, and procedural requirements associated with concessional finance access.

Current barriers to accessing concessional finance include complex commitment processes, stringent eligibility criteria, and limited technical capacity. Stakeholder consultations indicate that awareness of available funding windows remains low, leaving many opportunities untapped. Even when financing options are known, accreditation and application procedures are often lengthy and complex, sometimes taking several years before financing can be accessed. Many developers also lack the technical expertise to package projects in a way that meets the stringent eligibility criteria demanded by concessional funders. Implementing entities face similar capacity constraints that make it difficult to navigate the detailed due diligence, monitoring, and reporting obligations associated with these funds.

2. Domestic Commercial Finance

Historically, domestic financial institutions have only contributed around 14% of total financing for energy projects in Zambia. This limited involvement is due to a shallow market for local currency financing and equity, as well as the relatively high costs associated with these sources. Increasing domestic financing is beneficial for three key reasons:

1. *Mitigates currency risk*: While project revenue in Zambia is mostly generated in local currency, 80-90% of DFI and MDB funding is provided in foreign currency. This mismatch means that if the kwacha depreciates, the local revenue becomes insufficient to service foreign-denominated debt. That exposure to exchange rate volatility often leads to higher tariffs for consumers or financial distress for the project or utility. Domestic financing, which is denominated in local currency, helps to hedge against currency depreciation by aligning revenue with repayment obligations.
2. *Develops local capital markets*: When domestic financial institutions participate in energy projects, they build capability and confidence in financing infrastructure assets. Over time, this expands the availability of local financial products – such as the recent first green bond successfully issued by CEC for financing the Itimpi solar plant – while mobilising domestic savings into national development [16]. This reduces reliance on donor cycles and external borrowing, improving long-term financial resilience in the energy sector.
3. *Increases local ownership and accountability*: By investing in energy projects, domestic banks and institutions have a direct stake in a project's success. This motivates better oversight and governance and greater political accountability, which can help crowd-in further investment.

Recent interviews with domestic financial institutions have indicated an increasing appetite and commitment to financing local energy projects, fuelled in part by the ongoing power crisis. Many acknowledged the increasing challenges brought about by climate change and have expressed a strong willingness to invest in renewable energy. They also demonstrated a strong understanding of the sector and exhibited relative comfort with the sovereign, off-taker, and financing risks currently facing the country, viewing this as an advantage over international counterparts.[4] Further, they expressed optimism about innovative solutions to mitigate these risks, particularly following the successful issuance of Zambia's first green bond and the recent launch of the Carbon Market Framework [17], [18].

[4] The Climate Policy Initiative's (CPI) methodology for assessing investment attributes and risk tolerance across different institutions, grounded in extensive literature review, was applied [36].

An estimated US$76.9m of domestic finance is potentially available to Zambia's power sector annually. Based on historical growth rates in Bank of Zambia's Assets Under Management (AUM), the estimated domestic capital envelope for the energy sector (assumed as 5% of total asset base) is projected to increase from US$56m in 2025 to nearly US$450m by 2050 (Figure 10) [19].

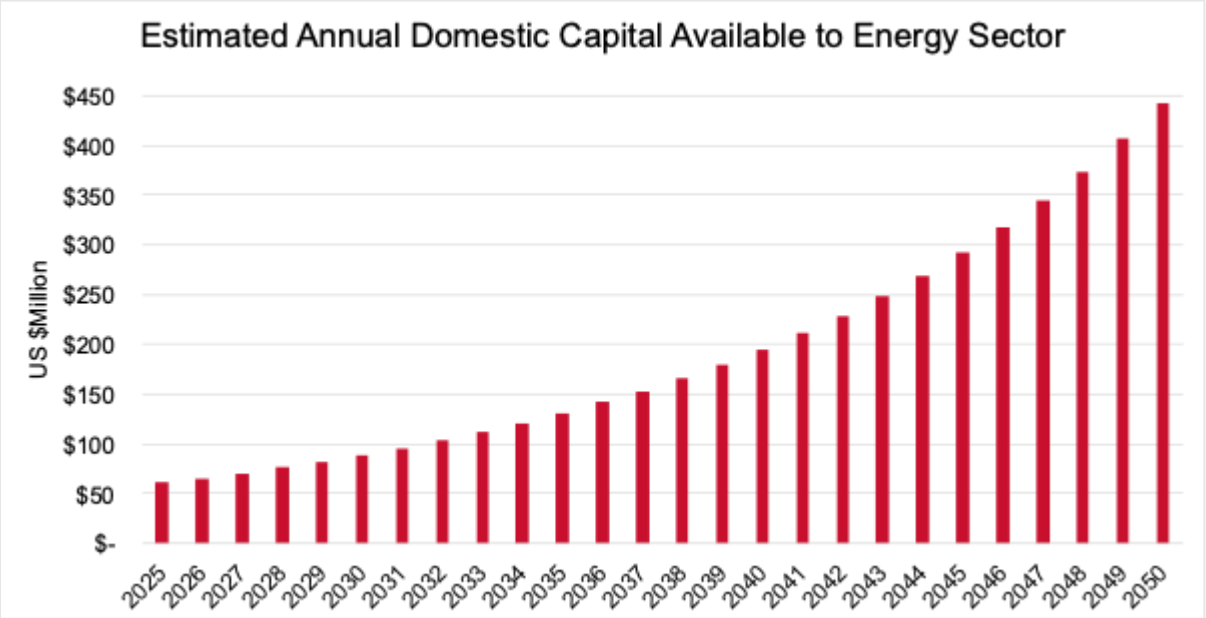

Figure 10. Estimated Annual Domestic Capital Available to Zambia's Energy Sector.

However, interviewees cited three key barriers to increasing energy investments:

1. *Limited technical capacity for evaluating projects*: Domestic commercial banks and pension funds have expressed a lack of technical and sector-specific expertise within their teams, hindering their ability to manage complex transactions and effectively conduct due diligence and project assessment.
2. *Mismatch between short loan tenors and long energy project timelines*: Domestic commercial lenders typically prefer shorter loan tenors (5-7 years on average), which does not align with the long-term repayment profiles required for most energy projects (20-40 years on average). This is especially true for institutions such as pension funds, whose withdrawal policies drive the need for short-term liquidity.
3. *Misaligned regulatory incentives and mandates*: The Pension Scheme (Investment Guidelines) Regulations (S.I. No. 50) (2021) significantly influence the investment behaviour of pension funds. These regulations mandate that pension schemes maintain at least 2.5% of their fund size in high-yield, low-risk government securities, while placing caps of 10%, 30% and 40% on investments in corporate bonds, foreign markets, and property, respectively [20]. These restrictions limit diversification opportunities.

4.1.2 Strategic Deployment and Blending of Concessional Finance and Domestic Commercial Finance

Strategic Principle 1: *Prioritise concessional finance and grant funding for project preparation and technical assistance to bridge early-stage financing gaps*

Concessional finance should be directed first toward early-stage project preparation, where high regulatory costs and limited funding create the most immediate bottlenecks. Developers report that regulatory fees, often paid upfront and out-of-pocket, can be prohibitively high.

For example, Environmental Impact Assessment (EIA) review fees for solar projects can reach ZMW1.3m (~US$50k) even for low-impact brownfield developments.

Several developers have completed these studies but cannot submit them due to these costs, leaving some projects in development for over a decade without reaching financial close. These challenges reflect broader trends on the continent, where an estimated 80% of infrastructure projects fail at the feasibility stage [21].

Delivering the IRP pipeline requires an estimated US$23.1m per year[5] for project preparation, yet only US$4.71m in currently available funds cover these activities (Figure 11). This underscores the urgency of closing this gap via alternative funding sources.

Figure 11. Project Stage Coverage by Fund Available to Zambia (FinTrack).

Dedicated technical assistance is also essential to address persistent capacity constraints that undermine project readiness. Local developers and financiers consistently report capacity constraints in packaging and evaluating energy projects for securing financing, reinforcing the need for dedicated TA facilities and capacity-building initiatives. However, while an estimated US$437.4 million in available funds can support TA, much of this is shared with investment-stage financing (Figure 11). A portion of these funds should therefore be explicitly reserved for TA activities to accelerate pipeline readiness and improve the effectiveness of all subsequent financing efforts.

[5] Based on the Ministry of Energy-OPPPI's estimate, project preparation costs were assumed to be 2.25% of total financing costs.

Strategic Principle 2: *In the near-term (2026-2030), a portion of concessional finance should be ring-fenced to provide liquidity support for national utility-offtake renewable projects.*

A competitive procurement and credit-support framework is being developed to facilitate the transition to Open Access. The Ministry of Energy is developing a Public Competitive Procurement Framework for Renewable Energy that provides a two-tiered credit support package that delivers predictable cashflows to the project and ensures compensation in the event of termination, without sovereign guarantees [22]. Full technical details are available in the forthcoming Competitive Procurement Framework.

The framework aims to draw from concessional resources for liquidity support, such as the sources identified in this roadmap. The MoFNP can also intervene to make selective payments to avoid termination. This approach enables the scaling up of competitive procurement, allowing the national utility to deliver on its public service mandate at more affordable rates and in compliance with the IMF programme.

Strategic Principle 3: *Prioritise concessional resources and domestic finance for national utility-offtake projects where they have the greatest de-risking impact, while projects procured competitively by large industrial customers should rely primarily on international commercial capital.*

Competitive-market projects should be financed primarily with international commercial capital, which is theoretically unlimited but harder to attract. Projects serving large energy customers face significantly lower off-taker and foreign-exchange risks. These consumers hold foreign-currency balance sheets, offer stronger creditworthiness profiles, and already pay tariffs in the US$0.09-0.10/kWh range. As a result, developers supplying these buyers can access international commercial debt and equity at lower costs of capital than those relying on national utility-offtake, as shown in Table 4. Figure 12 further shows that bankable PPA prices for small hydro, solar PV and wind under full commercial financing terms (US$0.06-0.09/kWh) remain aligned with what competitive consumers already pay.

National utility-offtake generation projects face higher financing costs and long-term tariff misalignment driven by currency depreciation. Figure 12 shows that while current Multi-Year Tariffs (MYT) are broadly sufficient to recover most -national utility-procured PPA costs today – with the exception of large run-of-river hydro – this cost-reflectivity deteriorates over time. Because MYT revenues are denominated in kwacha while PPA obligations are indexed to foreign currencies, anticipated currency depreciation erodes real cost recovery in the long-term. As a result, initially affordable national utility-backed PPAs become increasingly unbankable without concessional finance or domestic-currency instruments to cushion the FX gap.

This extends to critical public investments in transmission and distribution infrastructure, essential for system stability and reliability. Notably, distribution systems, which have traditionally benefitted from cross-subsidisation by bundled tariffs paid by mining and export customers, now face the risk of underfunding as these customers shift to the competitive market under Open Access.

Table 4. Bankable PPA Prices Under Full International Commercial Financing for IRP Generation Technologies (75% Debt, 25% Equity).

Generation Technology	Assumed Interest Rate for Intl Comm Debt	Assumed Cost of Equity Benchmark	Bankable PPA Price *(US$/kWh, 2026)*[6]
Biomass	22.8%	24.3%	0.04
Coal	21.2%	22.7%	0.05
Geothermal	23.8%	25.3%	0.06
Large Hydro	20.9%	22.4%	0.08
Small Hydro	14.3%	16.3%	0.06
Solar PV	15.8%	17.7%	0.09
Wind	15.8%	17.7%	0.09

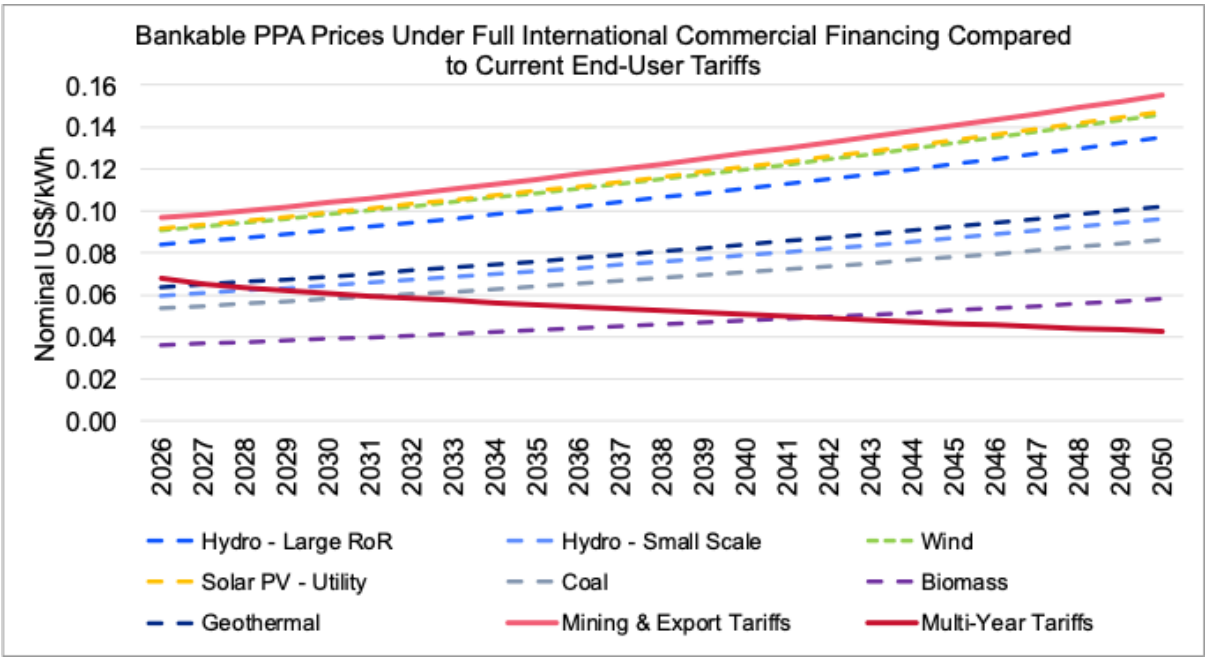

Figure 12. Bankable PPA Prices Under Full International Commercial Financing Compared to Current End-User Tariffs.

Concessional finance and domestic commercial capital should be prioritised for projects furthest from achieving cost-reflectivity, following a clear merit order. As shown in Table 4 and Figure 12, large hydro projects, with a starting bankable PPA price of US$0.08/kWh, should be prioritised as it is furthest from cost-reflectivity. This is followed by geothermal, which requires a bankable PPA price of US$0.06/kWh in 2026 that quickly exceed end-user tariff levels. Coal, at US$0.05/kWh, ranks next, while biomass, at just US$0.04/kWh in 2026 remains cost-reflective until around 2041 and should be deprioritised.

Strategic allocation of identified finance envelopes leads to an optimal financing mix of 40-50% concessional finance for T&D, large hydro, and geothermal, alongside 20% domestic commercial finance for coal and large hydro projects (Figure 13). This approach represents the most effective use of available resources within existing policy constraints. For example, certain domestic institutions face mandates that limit their ability to invest in new technologies with uncertain feasibility timelines and limited track records, such as geothermal.

[6] PPA prices shown are starting values for 2026 and are indexed at 2% annually to reflect long-term inflation in foreign-denominated contracts.

Moreover, many concessional and climate finance providers have withdrawn from supporting carbon-intensive fuels like coal, creating an opportunity for domestic lenders to fill the gaps in financing.

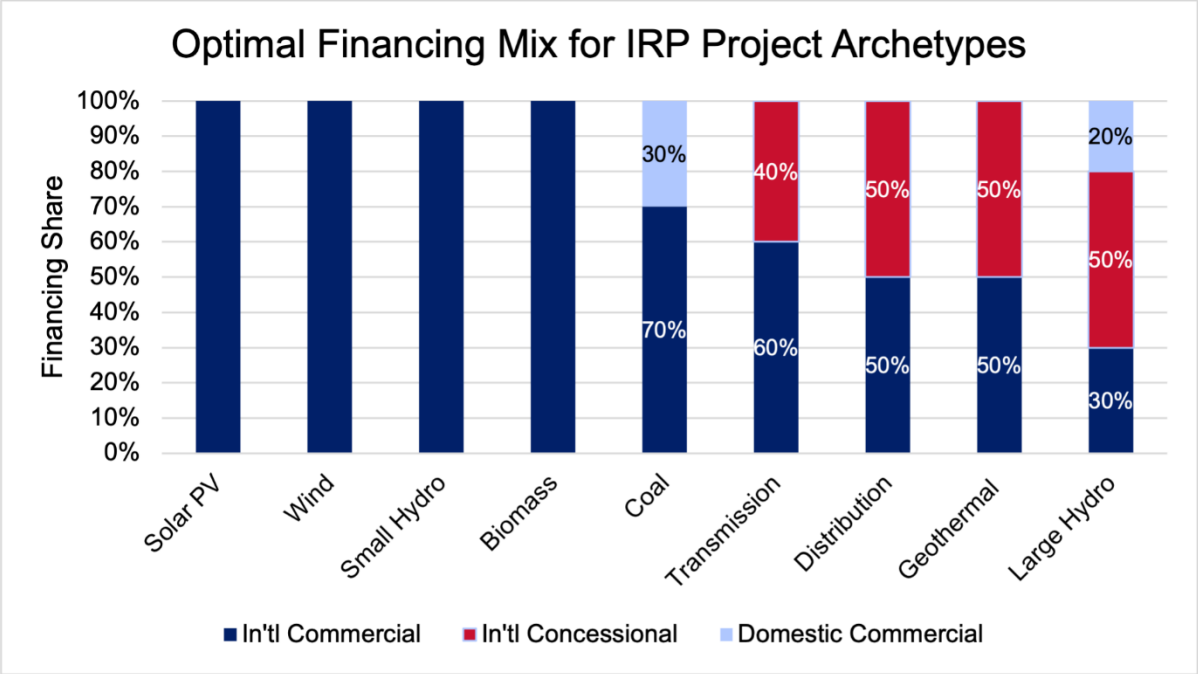

Figure 13. Optimal Financing Mix for IRP Project Archetypes.

An annual average of US$369m in international commercial finance is required for national utility-offtake projects. Figure 14 summarises the total annual financing flows of concessional, domestic, and international commercial if national utility-offtake projects were structured with the optimal financing mix. It indicates that following the full utilisation of concessional and domestic finance envelopes, an annual average of US$369 million in international commercial finance will still be required to address remaining financing needs. This translates to a sectoral financing mix comprising US$240m of concessional finance (35%), US$77m of domestic commercial finance (11%), and US$369m of international commercial finance (54%) annually. This marks a significant shift from a historical reliance on concessional sources toward an increasing dependence on private capital.

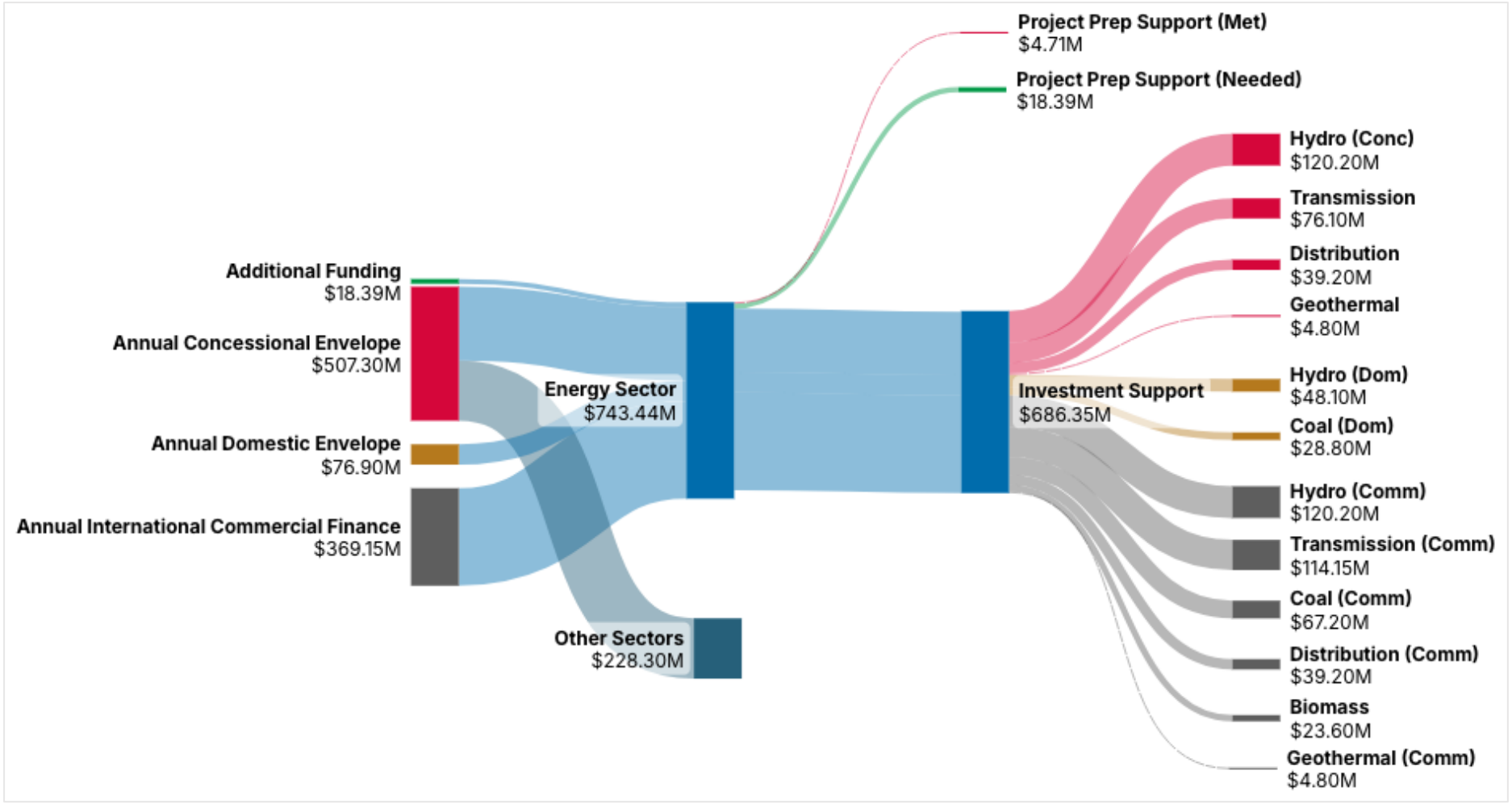

Figure 14. Sankey Diagram of Optimal Financing Flows for National Utility-Offtake IRP Projects.

Where possible, blending concessional and domestic can increase overall project bankability, reducing the required PPA price. Figure 15 illustrates this effect for large hydropower projects. While introducing concessional finance or domestic capital individually lowers the required PPA price relative to a 100% international commercial structure, blending them has a larger, cumulative impact. As financing costs compound over time, the benefit widens: the blended structure reduces the required PPA price by around US$0.03/kWh in 2026 and by US$0.05/kWh in 2040.

Domestic investors are also far more willing to participate when concessional finance and strong risk-mitigation tools are in place. Interviews with domestic financial institutions consistently emphasised that concessional finance and RMI significantly increase their appetite to invest. These tools are viewed as essential given the high upfront costs and long payback periods typical of energy projects. Partnerships with development finance institutions were also seen as highly favourable, as they provide a clear signal of project credibility and rigorous due diligence.

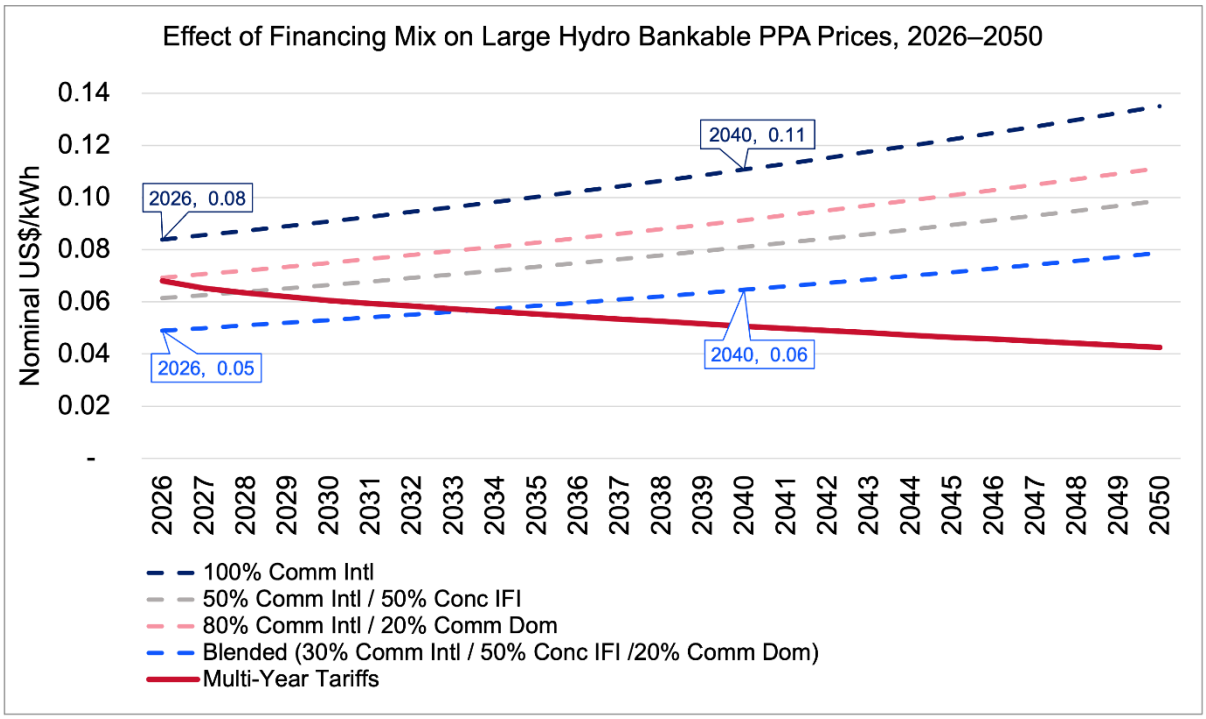

Figure 15. Effect of Blended Finance on Bankable PPA Prices for Large Hydro, 2026-2050.

Optimal deployment of limited concessional finance and domestic capital can reduce the weighted-average PPA price across technologies by US$0.01/kWh in 2026 and by up to US$0.02/kWh by 2050. By directly lowering the weighted average cost of capital, concessional finance lowers the bankable PPA price for capital-intensive public service assets procured by the national utility, thereby alleviating the financial burden on end-user tariffs. Similarly, strategic allocation of domestic capital to national utility-offtake projects reduces forex exposure and consequently lowers borrowing costs, improving overall project bankability.

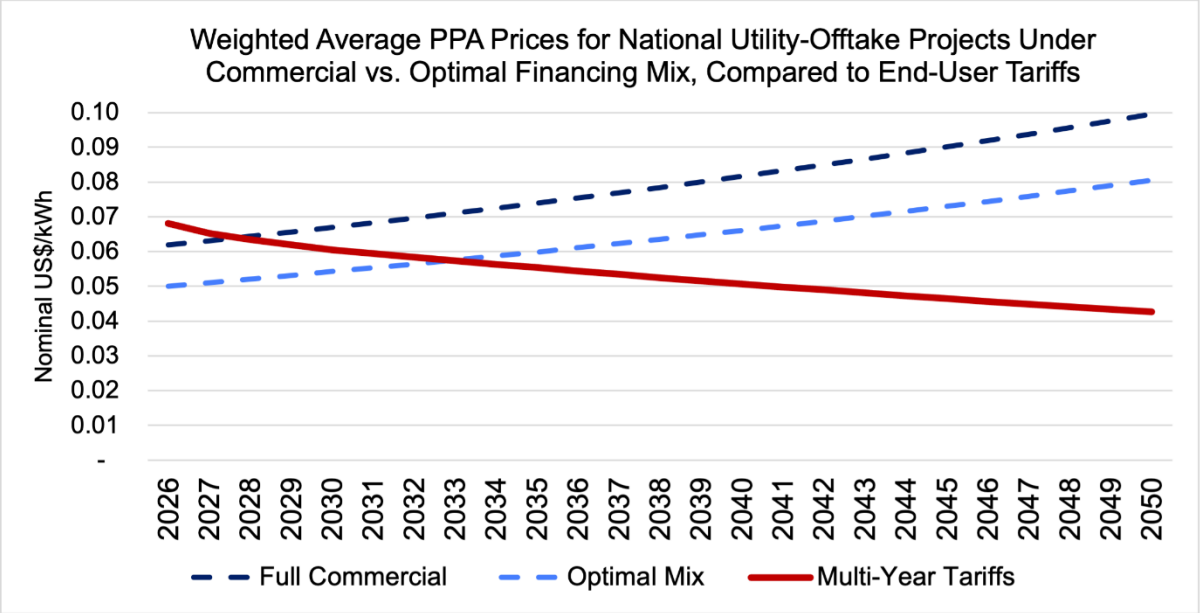

Figure 16. Bankable PPA Prices for National Utility-Offtake Projects Under Fully Commercial vs. Optimal Financing Mix Compared to Current End-User Tariffs, 2026-2050.

Optimally allocating scarce concessional and domestic capital across the IRP pipeline can reduce the net financing gap by US$5.1bn compared to a scenario relying solely on international commercial finance (Figure 17). However, a serious financing gap persists post-mid-30s, underscoring the importance of closing the gap through tariff reform and other fundraising mechanisms.

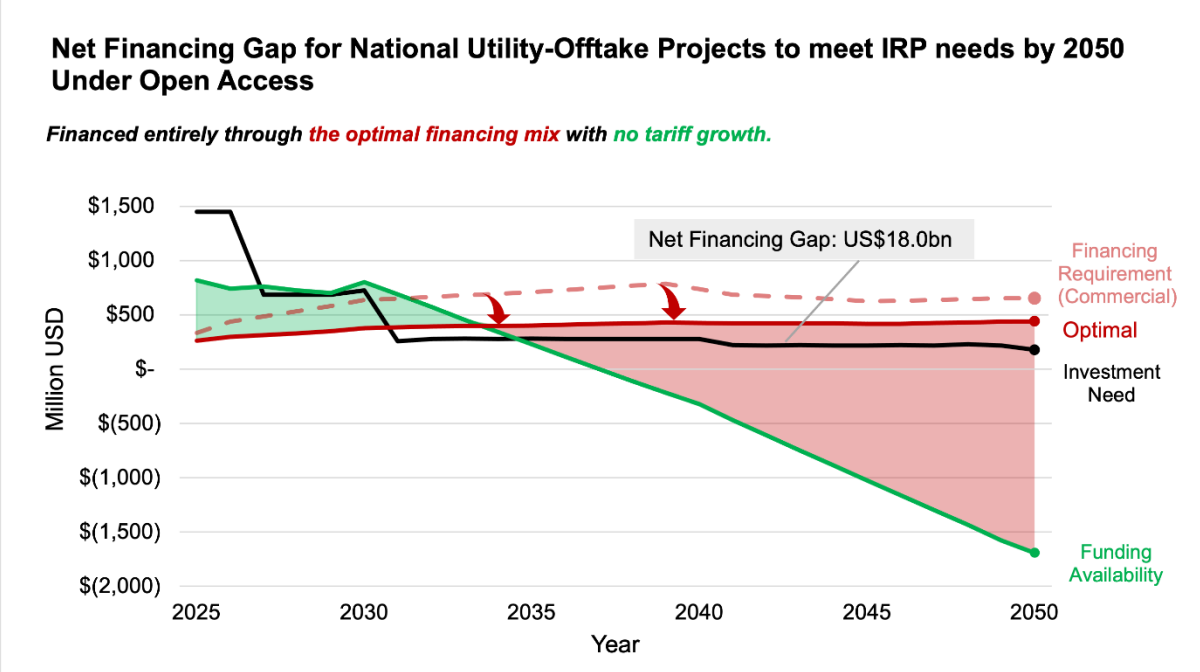

Figure 17. Net Financing Gap Under the Optimal Future Financing Mix and Transition to Open Access, 2025-2050 (MINFin).

4.1.3 Strategic Mobilisation of Concessional Finance and Domestic Commercial Finance

Strategic Principle 4: *Sequence concessional finance mobilisation by targeting the most accessible, high-volume windows and pursuing more restrictive funds as institutional capacity improves.*

Understanding how available concessional finance windows vary across accessibility, scale, and concessionality provides a basis for sequencing mobilisation efforts. Figure 18 illustrates the trade-offs between concessionality,[7] volume available, and the difficulty of access across current climate finance windows. Given existing access challenges, funds positioned in the lower-left quadrant – offering higher volumes with fewer entry barriers – represent the most realistic near-term opportunities. Over time, more complex or restrictive funds in the upper-right quadrant can be pursued as project maturity and institutional capacity improve. Following SP5, funds targeting climate adaptation[8] are also ranked higher in the priority list. Table 5 provides a summary of key fund characteristics in order of prioritisation.

Table 5. Summary of Fund Characteristics in Priority Order (FinTrack).

Fund	Est. Annual Allocation	Historical Funding Accessed	Concession-ality (%)	Adaptation Target (%)	Accessibility (Criteria Count)	Priority Level
WB (IDA)	$204.93	$78.19	57%	50%	7	High
IMF (RST)	$31.21	$ -	60%	50%	6	High
NPC (DGM)	$24.90	$0.19	100%	50%	9	High
ADF	$38.16	$41.34	56%	50%	9	High
GCF	$27.04	$12.61	86%	50%	10	High
EIB	$140.46	$31.02	9%	15%	7	High
PPCR	$5.36	$5.71	100%	100%	11	High
CAW	$5.91	$ -	100%	75%	7	Medium
LDCF	$1.25	$1.08	100%	100%	5	Medium
AF	$1.16	$0.03	100%	100%	8	Medium
ADF (PBA)	$8.15	$ -	56%	50%	9	Medium
GEF-8	$4.37	$4.23	86%	50%	9	Medium
ADF (TSF)	$4.18	$ -	56%	50%	9	Medium
RPSP	$1.75	$0.16	100%	50%	9	Low
CTF	$5.68	$ -	100%	0%	10	Low
PPF	$1.50	$ -	100%	50%	10	Low
SGP	$0.23	$ -	100%	50%	5	Low
SREP	$0.57	$ -	100%	50%	10	Low
TF(PPG)	$0.30	$ -	100%	50%	9	Low
SCCF	$0.19	$ -	100%	50%	9	Low
FIP	$ -	$ -	-	0%	-	Low

[7] The overall concessionality of each fund is summarised using the Grant Element, which reflects how far the terms of a loan deviate from market-rate financing. This is calculated based on the OECD methodology and expressed as a percentage, where 0% reflects fully commercial terms and 100 represents a pure grant.
[8] In absence of clear allocation between Adaptation and Mitigation targets, funds were assumed to have an equal mix of both Adaptation and Mitigation activities.

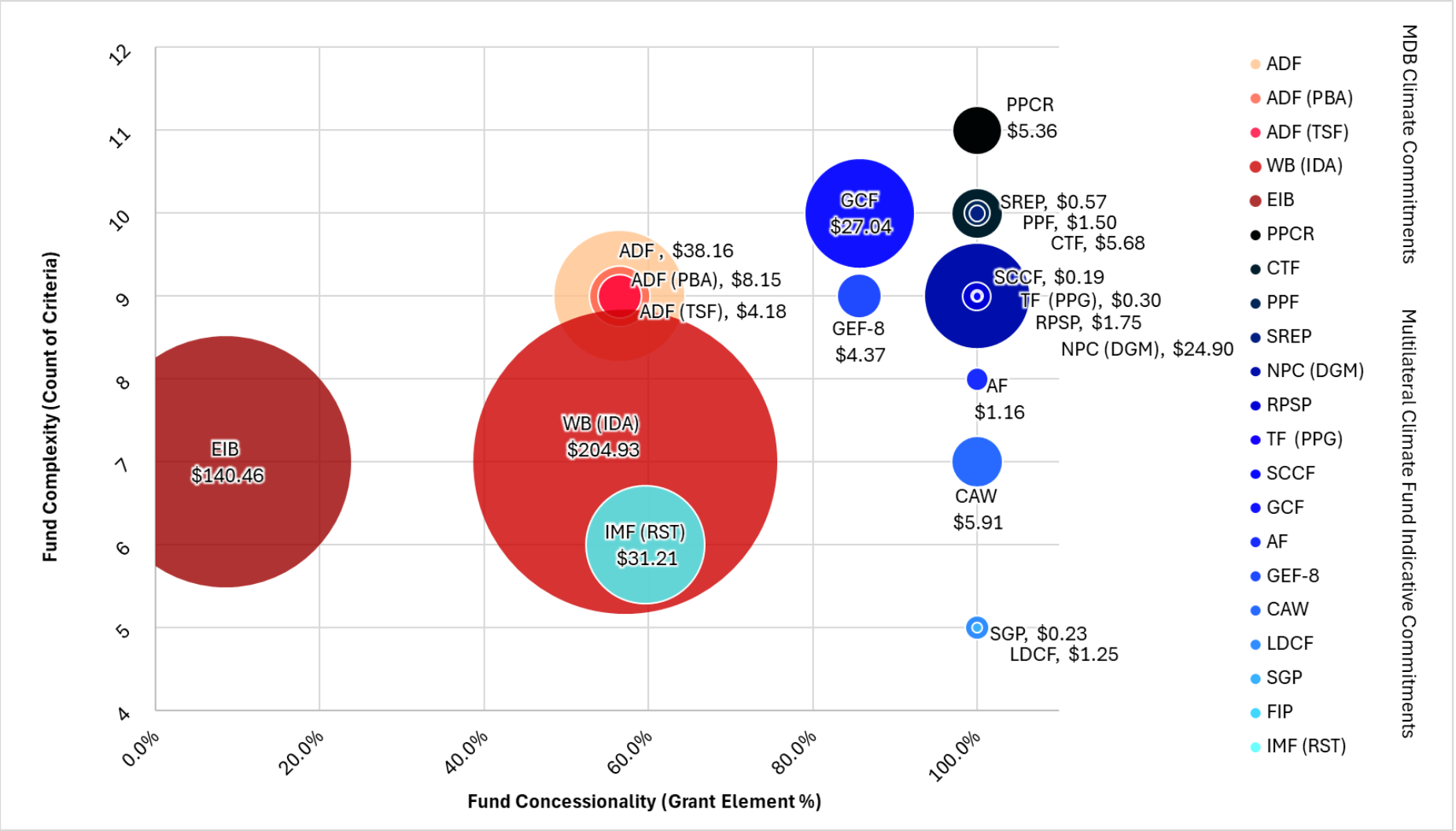

Figure 18. Annual Volume of Climate Finance Available to Zambia by Grant Element and Criteria Count (Source: FinTrack).

Strategic Principle 5: *Leverage the modelled cost premium of climate adaptation of the power system as a clear justification for mobilising targeted adaptation finance.*

Zambia's IRP prioritises adaptation to increasingly severe drought driven by climate change. In line with the 2023 National Adaptation Plan (NAP), the IRP aims to reduce reliance on hydropower in the drought-prone Zambezi River basin, currently accounting for around 85% of total installed capacity, by diversifying the generation mix and expanding hydropower capacity in the more climate-resilient Northeastern region.

To understand the cost implications of this adaptation strategy, the IRP was compared against a business-as-usual (BAU) pathway that continues investment in Zambezi hydropower. This scenario assumes development of major projects such as Batoka Gorge without opening up the Northeastern region, which currently lacks supporting grid infrastructure, allowing for a direct comparison with the IRP-aligned pathway.

The IRP's adaptation pathway carries a capital cost premium of around US$7 billion between 2025 and 2050, or an average of US$152 million per year (Figure 19). This represents the incremental cost of climate adaptation in the power sector, providing a strong rationale for meeting key fund criteria. It should be leveraged to strengthen project proposals and access to international adaptation finance.

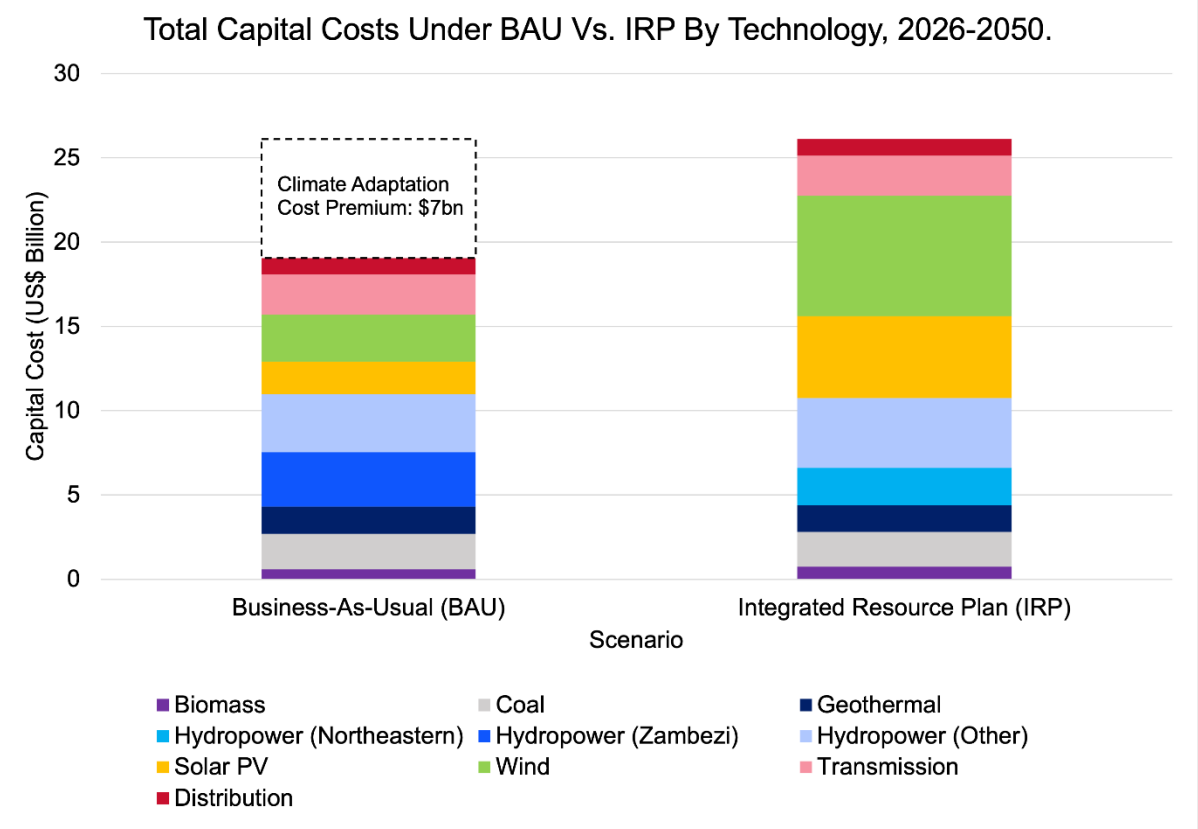

Figure 19. Total Capital Costs Under IRP Versus BAU by Technology, 2026-2050 (OSeMOSYS).

Climate finance efforts for IRP implementation should therefore prioritise climate and development funds that target adaptation. Table 5 shows the indicative allocation targets of adaptation versus mitigation financing across climate and development funds. Three funds target adaptation only, providing an estimated US$7.8m per year. Table 6 provides a shortlist of funds targeting climate adaptation activities and more details on their accreditation status and implementation entities in Zambia.

However, given the low volumes of adaptation funding and high barriers to access, it may be more strategic to pursue larger, less restrictive funds that do not specifically favour climate mitigation or adaptation, together representing an additional US$199.2m.

Taken together, this represents well over the US$152m per year of adaptation finance required to cover the adaptation cost premium, though this assumes full mobilisation and disbursement for the energy sector. While adaptation finance has traditionally prioritised agriculture, water, and disaster relief management, energy should be recognised as equally critical in Zambia, given its unique vulnerability to climate impacts and its central role in economic resilience.

Table 6. Shortlist of Adaptation Funds for IRP Implementation (FinTrack).

Fund	Est. Annual Allocation	Historical Funding Accessed	Accreditation Status	Implementation Entities
Pilot Program for Climate Resilience (PPCR)	$5.36m	$5.71m	N/A	IBRD, AfDB
Adaptation Fund (AF)	$1.16m	$0.03m	In progress	ZICB
Least Developed Countries Fund (LDCF)	$1.25m	$1.08m	Uses GEF-accredited agencies	UNDP, AfDB, WB, UNEP
Climate Adaptation Window (CAW)	$4.43m	$-	N/A	AfDB
Green Climate Fund (GCF)	$13.52m	$6.31m	Obtained	DBZ, ZANACO

Strategic Principle 6: *Enable domestic financial institutions to participate in large national utility-backed energy projects through light-touch incentives and prudential policy support.*

Domestic investors naturally gravitate toward competitive-market renewables, but this misses where they can deliver the greatest system-level impact. While domestic financiers are well-positioned to participate in Zambia's emerging competitive market – given their shorter investment horizons, smaller ticket sizes, and lower tolerance for perceived governance risk – this natural allocation does not align with where their capital delivers the greatest impact. Large national utility-backed hydro, grid, and baseload projects remain the most in need of FX-risk reduction and access to non-concessional financing sources.

Domestic appetite for energy investment is real and growing, but current mandates limit where this capital can flow. Interviews with domestic commercial institutions reveal a rising commitment to financing local energy projects, fuelled in large part by the ongoing power crisis. These institutions also demonstrated a strong understanding of Zambia's project landscape, viewing their sectoral knowledge as a key advantage over foreign investors. However, many expressed low tolerance for governance and off-taker risk, and hesitancy toward newer technologies such as geothermal, where timelines and track records remain uncertain.

Light, market-compatible policy instruments are needed to gently nudge domestic capital toward national utility-offtake projects. Interviewees were not unwilling to consider large hydro, grid, or coal assets; rather their mandates and risk tolerances restrict participation without targeted support.

GRZ can introduce non-distortionary policy measures, such as modest fiscal incentives or adjusted investment guidelines for pension funds, to enable domestic investors to operate within them on more competitive terms. These solutions are further expanded on in the recommended policy actions below.

4.1.4 Recommended Policy Actions

Policy Action 1: *Strengthen fund-tracking and matching through a centralised unit.*

A centralised coordination function is essential for proactively enhancing access to suitable concessional financing opportunities for pipeline projects. The forthcoming Climate Finance Unit (CFU) should lead this function and be responsible for:

- *Monitoring fund availability and eligibility requirements across climate and development funds*, leveraging tools like FinTrack.
- *Coordinating with MoE to conduct periodic developer interviews and assess alignment with fund-specific criteria*. This will help identify project eligibility gaps and direct targeted support for strengthening project proposals.
- *Matching funds with eligible projects in the pipeline*, including early-stage project preparation financing, to ensure projects are strategically positioned and accelerating financial close.
- *Developing and maintaining relationships with core funders*.

Policy Action 2: *Set up a dedicated fund to cover early-stage project preparation activities, operating through an open call for applications.*

To close early-stage financing gaps, the MoE should work with the forthcoming CFU to establish a dedicated fund. This initiative would serve several key functions:

- *Pooling concessional resources*: The CFU should take the lead in aggregating financial contributions from various concessional sources, creating a robust pool of funds specifically earmarked for early-stage project preparation.
- *Leveraging budgetary contributions*: The GRZ could consider filling any remaining gaps by allocating a portion of the annual budget for early-stage project assistance.
- *Facilitating competitive access*: The MoE should operationalise the fund by initiating periodic calls for application through a transparent and competitive process. Project developers can submit their proposals directly, which would be evaluated against a clear eligibility criteria designed to ensure a baseline level of preparedness and demonstration of commitment.

Policy Action 3: *Strengthen alignment with the six key eligibility criteria to unlock the majority of concessional finance.*

Six key eligibility criteria determine access to most major sources of concessional finance. Figure 20 maps key eligibility criteria against associated finance volumes, distinguishing between criteria that are strictly *required* and those that *contribute* towards but are not essential for funding access. The figure also highlights the share of finance that remains unutilised under each criterion, indicating that meeting six priority areas – Project Management, Gender and Social, Feasibility Studies, Debt Risk, Policy, and Mitigation/Adaptation – would unlock most of the available concessional finance.

Table 7 shows the breakdown by fund, while Table 8 provides detailed descriptions of each criterion. Zambia already aligns with most eligibility criteria, but these are not always packaged and communicated in ways that match donor expectations. Table 8 outlines the specific actions required to strengthen positioning and increase competitiveness for concessional resources.

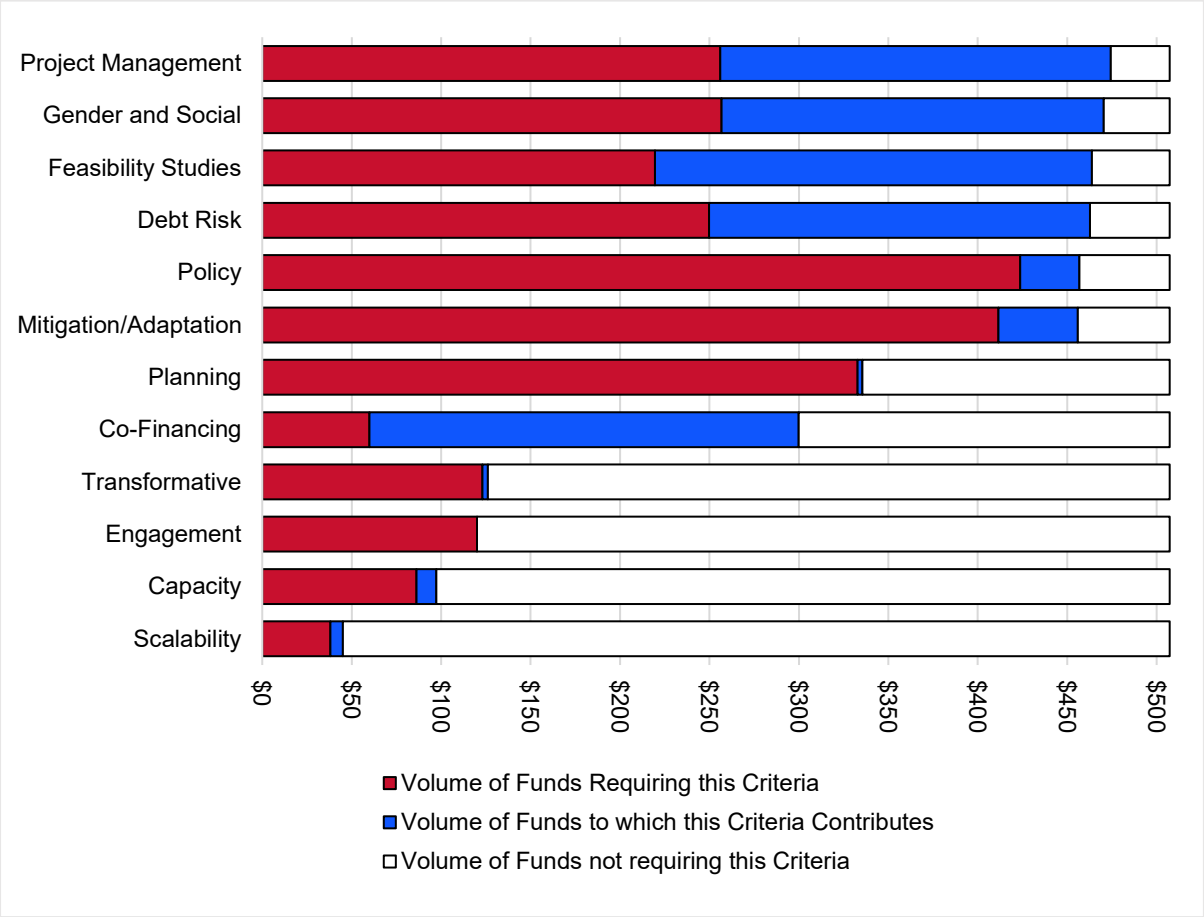

Figure 20. Volumes of Finance Required by Criteria (FinTrack).

Table 7. Summary of Access Criteria for Development and Climate Funds (FinTrack).

	Debt Risk	Project Management	Engagement	Scalability	Feasibility Studies	Policy	Capacity	Gender and Social	Transformative	Planning	Mitigation and Adaptation	Co-Financing
NPC (DGM)												
CAW												
CTF												
PPCR												
RPSP												
PPF												
LDCF												
AF												
TF (PPG)												
SREP												
SGP												
SCCF												
FIP												
GCF												
GEF-8 (BD)												
GEF-8 (LD)												
GEF-8 (CC)												
IMF (RST)												
WB (IDA)												
ADF												
ADF (PBA)												
ADF (TSF)												
EIB												

: Criteria are likely to be Required
: Criteria are likely to Contribute to Access
: Criteria are not likely to be Required

Table 8. Summary of Key Fund Eligibility Criteria and Key Actions to Improve Access (FinTrack).

Criteria	Priority	Definition	Key Actions Required
Project Management	**Higher**	Demonstrates cost-effective project management and clear legal accountability for financial obligations.	Require transparent and competitive tendering aligned with the Public Procurement Act (2020) to reduce procurement risk and inflated costs.
Gender and Social	**Higher**	Shows strong gender inclusion, community engagement, and transparent decision-making.	Adopt MoE's Social Safeguards Framework (2024) to embed inclusion, transparency, and community benefits from project design through implementation.
Feasibility Studies	**Higher**	Provides evidence of Environmental and Social Impact Assessment and feasibility studies.	Streamline submission processes for developers facing prohibitive fees and delays *(SP3).*
Debt Risk	**Higher**	Further debt is sustainable and does not deepen national debt crises.	Strengthen project-level risk allocation through cost-reflective tariffs and credit enhancement structures *(SP5).*
Policy	**Higher**	Align with and enable progress towards goals outlined under climate targets such as the Paris Agreement, among others.	Explicitly link project outcomes to IRP targets, Zambia's NDC, NAP, Green Growth Strategy, among others, in all proposals.
Mitigation/Adaptation	**Higher**	Demonstrates climate mitigation and adaptation potential that meet fund-specified targets.	Use the quantified adaptation cost premium as a core justification for adaptation-aligned funding *(SP2).*
Planning	**Medium**	Projects are underpinned by evidence-based research and country ownership.	Reference IRP-alignment which is based on least-cost, evidence-based modelling.
Co-financing	**Medium**	Mobilises co-financing from private sector to develop capacity for further investments.	Leverage concessional finance and RMI to effectively de-risk projects and crowd-in private capital (*SP4&7).*
Transformative	**Lower**	Potential to influence regional technology costs and policy environments.	Articulate system-wide impacts, e.g., grid stability, technology learning curves, and declining costs over time.
Engagement	**Lower**	Evidence of successful prior engagement in the country.	• Mention prior engagements and successful past applications. • Maintain a national engagement log.
Capacity	**Lower**	Demonstrates sufficient institutional capacity or plans to develop it to ensure knowledge transfer and country ownership.	Leverage existing TA facilities and capacity building opportunities (*SP3 & PA3).*
Scalability	**Lower**	Demonstrates potential to scale deployment and impact nationally or regionally.	Include plans for phased expansion and highlight replicability beyond the pilot.

Policy Action 4: *Institutionalise capacity building for project preparation and fund applications amongst local developers and implementing entities.*

Embedding modelling and technical capabilities within national institutions, rather than delivered through ad-hoc training, is essential for building long-term, locally rooted expertise. This, in turn, strengthens Zambia's ability to access and deploy concessional finance effectively while building a robust, sustainable project pipeline.

To support this, several initiatives are already underway:

- *Centre for Sustainable Energy Modelling (CSEM)*: currently being established by CIG Zambia within the Ministry of Energy as a central hub for sustained technical assistance, a national energy data repository, and capacity building on tools such as OSeMOSYS and FINPLAN.
- *MSc in Climate and Energy Modelling (planned for 2026-7)*: an interdisciplinary programme to train students in energy and financial modelling tools including OSeMOSYS, CLEWS and FINPLAN.
- *CCG's Energy Modelling Platforms (EMPs)*: quarterly, intensives hands-on training sessions applying open-source modelling tools applied to real datasets and live project contexts.

Policy Action 5: *Introduce modest fiscal instruments to encourage domestic investment in critical energy projects.*

These measures should be small, predictable, and explicitly tied to projects that support national energy security and system reliability, including but not limited to:

- *Reduced or waived withholding tax* for domestic debt holders in eligible power-sector infrastructure loans.
- *Time-bound tax relief on interest income* earned from long-term infrastructure bonds.
- *Targeted corporate tax allowances* for financial institutions that allocate a defined share of their portfolio to eligible energy infrastructure investments.
- *Accelerated depreciation or capital allowances* for domestic investors taking equity shares in eligible projects.

Policy Action 6: *Revisit pension investment guidelines and withdrawal rules to expand the investment capacity of public pension funds.*

Current pension investment guidelines unintentionally limit the ability of public pension funds to participate in long-term energy infrastructure. Current provisions in the Pension Scheme (Investment Guidelines) Regulations (S.I. No. 50) (2021) mandate that pension schemes maintain at least 2.5% of their fund size in high-yield, low-risk government securities, while placing caps of 10%, 30% and 40% on investments in corporate bonds, foreign markets, and property, respectively [20]. These limits reduce opportunities for portfolio diversification and constrain participation in local infrastructure investments.

Additionally, current pension withdrawal benefits constrain long-term liquidity. This includes the new National Pension Scheme Amendment Bill in 2023, which allows a one-off pre-retirement withdrawal of up to 20% of total contributions. While this can support household liquidity and boost economic activity, it also reinforces the need for pension schemes to hold short-term liquidity. A balanced approach is therefore needed to preserve the social function of pension withdrawals while still enabling long-term investment in critical infrastructure.

GRZ could consider:

- *Revising asset-class caps* to allow slightly higher allocations to local infrastructure investments.
- *Aligning pension withdrawal rules with infrastructure investment horizons*, reducing pressure for short-term liquidity and enabling pension funds to provide longer tenors on infrastructure investments.

Policy Action 7: *Build long-term technical capacity within domestic financial institutions to improve project evaluation, risk assessment, and due diligence of energy projects.*

Domestic financiers need stronger technical capacity to evaluate energy technology-specific risks and conduct rigorous due diligence. Interviews made clear that interest in the sector is growing, but limited sector-specific expertise is limiting their ability to participate in large, complex energy projects.

In the near-term, domestic institutions can leverage external expertise while internal capacity is being built. Several interviewees noted that hiring technical consultants for potential projects has been highly effective for navigating complex transactions and getting projects to financial close. Domestic financiers can also take advantage of existing technical assistance facilities and capacity building initiatives as identified in PA4, which provide tailored support on project appraisal, risk analysis, and financial structuring.

Over the longer-term, internal structures should evolve to embed specialised energy-finance expertise within institutions. This could include establishing small, dedicated desks or units focused on energy and infrastructure finance, responsible for pipeline development, due-diligence processes, and navigating accreditation requirements for concessional or climate funds. ZANACO is a leading example, having received GCF-accreditation in 2022, and actively building capacity.

4.2 Pillar 2: Tariff Reform for Fairness and Cost Recovery

4.2.1 Background

Zambia has historically maintained electricity tariffs below the cost of supply. This approach was viable when production costs were low due to inexpensive hydropower, but became untenable starting from the 2019 power crisis, when the national utility was compelled to import electricity at prices far above its selling rate [3]

Macroeconomic pressures and local currency depreciation have propelled the national utility into a debt crisis. High IPP costs, reduced fiscal support during the economic downturn and COVID-19, and the sharp depreciation of the kwacha all compounded the national utility's financial strain. The weakening currency further inflated foreign-denominated IPP and import payments, while most of the national utility's revenues are collected in kwacha.

The 2023-2027 Multi-Year Tariffs Framework (MYTF) is inadequate to meet IRP investment needs [4]. Designed using lower-cost assumptions from the 2019 Cost of Service Study (COSS), the MYTF does not account for the significantly higher investment requirements under the IRP [5].

While the MYTF provides for annual reviews and tariff adjustments based on economic fundamentals, depreciation of the kwacha has outpaced the framework's assumptions,[9] with annual adjustments unable to keep pace with exchange rate movements.

Zambia's electricity market is characterised by a dual structure that drives significant cross-subsidisation (Table 9). Domestic consumers face affordability constraints and therefore pay low, kwacha-denominated tariffs, while mining and export customers are able and willing to pay higher, foreign-denominated prices for reliable supply. This structure allows higher-value foreign-denominated revenues to partially offset shortfalls from domestic segments, though the sector as a whole remains far from cost-reflective.

Table 9. Characteristics of Zambia's Electricity Customer Segments.

Customer Category	Average Tariff Level	Billing Currency	Assumed Market Access Under Open Access	IRP Demand Share (2026-2030)	IRP Demand Share (2031-2050)
Residential	Low	Kwacha	Regulated	22%	17%
Commercial & Industrial	Low	Kwacha	Regulated	7%	9%
Agricultural	Low	Kwacha	Regulated	18%	32%
Mining	High	Foreign	Competitive	40%	27%
Exports	High	Foreign	Competitive	13%	15%

The transition to Open Access will require deliberate measures to maintain existing cross-subsidisation. As mining and export customers shift toward competitive supply arrangements, the national utility's revenue base risks erosion and greater exposure to foreign exchange volatility. Targeted mechanisms, such as equitable transmission and wheeling charges, will be critical for preserving affordability for domestic consumers while progressing toward sector-wide cost reflectivity.

4.2.2 Strategic Principles and Expected Impact

Strategic Principle 7: *Ensure that the socialisation of distribution costs in unbundled tariffs is managed equitably and sustainably.*

Under Open Access, sustaining system-wide cost recovery becomes more challenging as services become unbundled**.** Currently, tariffs are bundled across all consumer groups, aggregating generation, transmission, and distribution costs regardless of actual service usage. However, under the new framework, competitive consumers will only incur charges for transmission services, whereas they previously helped subsidise the distribution network they do not utilise. This means that distribution-related costs will fall entirely on regulated consumers, highlighting a key affordability challenge in the transition.

Unbundled distribution tariffs fall significantly short of cost-reflective levels under current apportioned multi-year tariffs.[10] Figure 21 illustrates that the revenue generated under these tariffs is insufficient to meet required levels, even without accounting for the allowed return of 6%.

[9] According to the ERB, the MYT were based on a fixed exchange rate of K16.5/$1 for the 2023-2027 period, with planned adjustments during annual true-up reviews. However, actual depreciation has far exceeded these projections, reaching K20.5/$1 in 2023, K26.1/$1 in 2024, and K28.1/$1 in 2025.
[10] Based on the recommended allocation for unbundled voltage-use tariffs in the Cost-of-Service Study (2021), distribution tariffs are assumed to account for 23% of the total multi-year tariffs [37].

Due to front-loaded distribution investments under the IRP, an average annual revenue shortfall of 1.34¢/kWh is expected between 2025-2030 with a 6% return, narrowing to 0.55¢/kWh from 2031-2050.

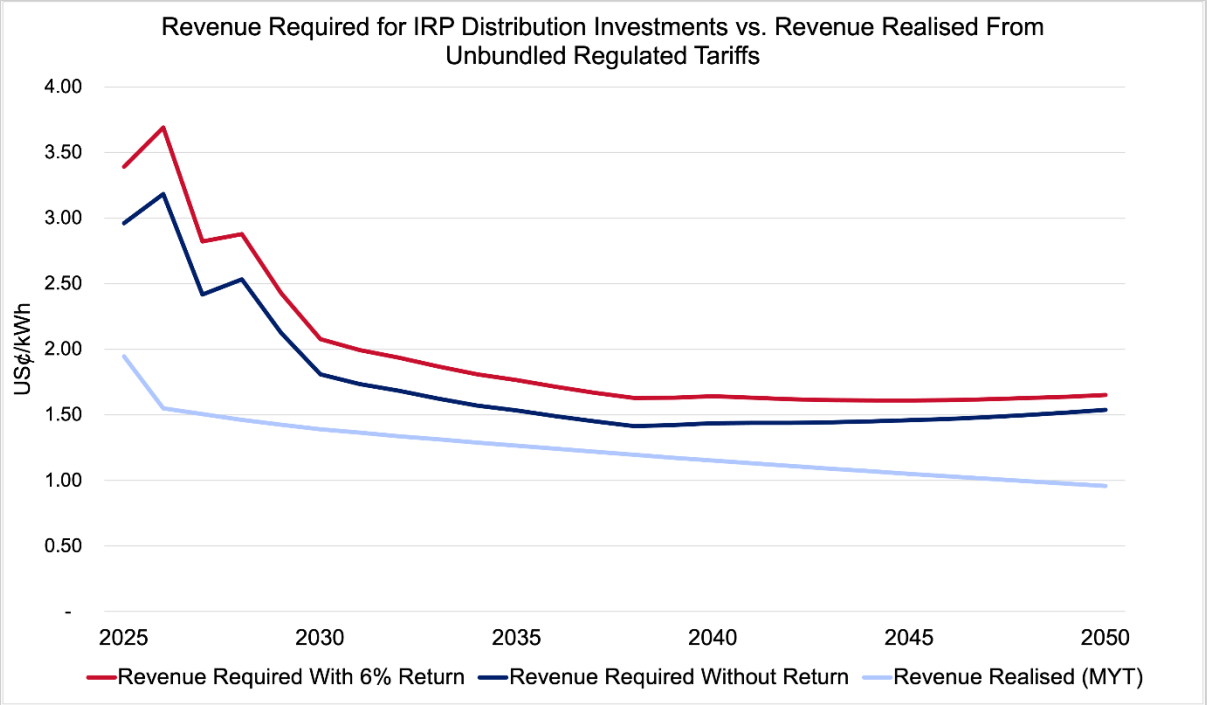

Figure 21. Revenue Required for IRP Distribution Investments vs. Revenue Realised from Unbundled Regulated Tariffs, 2025-2050.

Ensuring affordability for regulated consumers will require deliberate regulatory decisions on how distribution costs are socialised across consumer groups. As competitive consumers transition to direct procurement, regulators will need to determine how remaining and new distribution network costs are allocated in a way that is both sustainable and equitable, without overburdening regulated users.

Strategic Principle 8: *A moderate increase in regulated tariffs may be necessary to combat increasing exposure of the national utility's revenue base to foreign exchange risks*

As an increasing share of competitive customers shifts toward competitive supply, the national utility's revenue base risks erosion and increased exposure to forex risks. Without any increase in regulated tariffs, its annual funding availability is projected to fall below financing requirements after 2033 and below zero after 2036. The primary driver of this decline is the expected depreciation of the local currency, which averaged 13.6% per year between 2010 and 2024 (with a median of 9.8%) [23]. Therefore, a moderate increase in tariffs will be necessary to mitigate some of these effects, along with ensuring that adjustments during true-up reviews can adequately respond to unexpected shocks.

However, increasing regulated tariffs alone won't be enough to close the financing gap when competitive customers completely exit the national utility's revenue base around 2040. Implementing nominal annual tariff increases of 4%, 6%, and 8% (after current MYT ends in 2027) would postpone the point at which funding availability falls below financing requirements to 2036, 2039, and 2042, respectively (Figure 22). However, these growth rates are unlikely to be sustainable in the long-term due to affordability concerns, underscoring the need for additional strategies to bridge the gap.

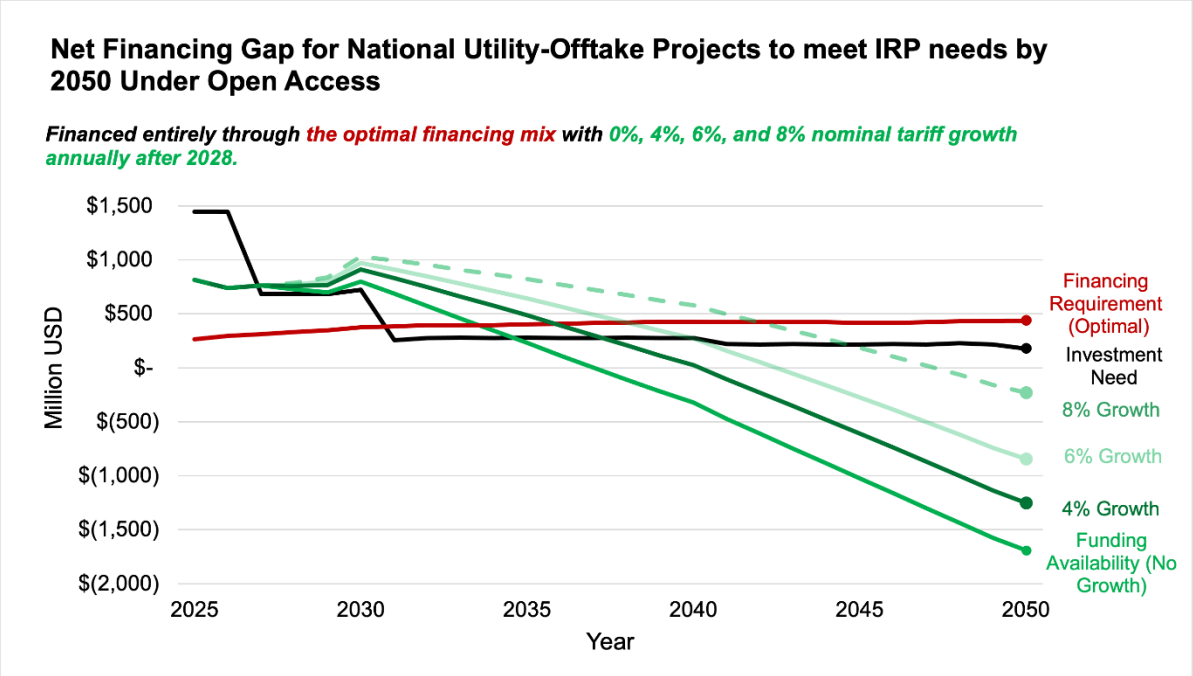

Figure 22. Net Financing Gap Under the Optimal Future Financing Mix and Different Tariff Growth Rates Under Open Access, 2025-2050 (MINFin).

Strategic Principle 9: *Ensuring domestic tariff affordability and the long-term viability of the sector hinges on maintaining some level of cross-subsidisation through fair and transparent transmission pricing.*

Transmission pricing under Open Access must ensure fairness and non-discrimination, while maintaining system-wide cost recovery. The Energy Regulation Board is responsible for setting transparent and non-discriminatory transmission prices that enable fair competition across all users. However, the framework must also allow for some degree of cross-subsidisation to ensure overall cost-reflectivity and recovery of shared system costs, without compromising the core principle of equal access to the grid.

In addition to paying a wheeling fee, competitive customers are likely to continue contracting with the national utility to fulfil a portion of its energy needs, but this alone won't be enough to close the financing gap. Given the intermittent nature of competitive technologies, most of these consumers will continue to contract with the national utility for stability support and during periods of low supply, where the national utility ensures that adequate capacity is available to meet their demand. However, as Figure 23 illustrates, competitive consumers contracting 10%, 20% or 30% of their total capacity with the national utility at current capacity fees only marginally shifts the funding availability curve.

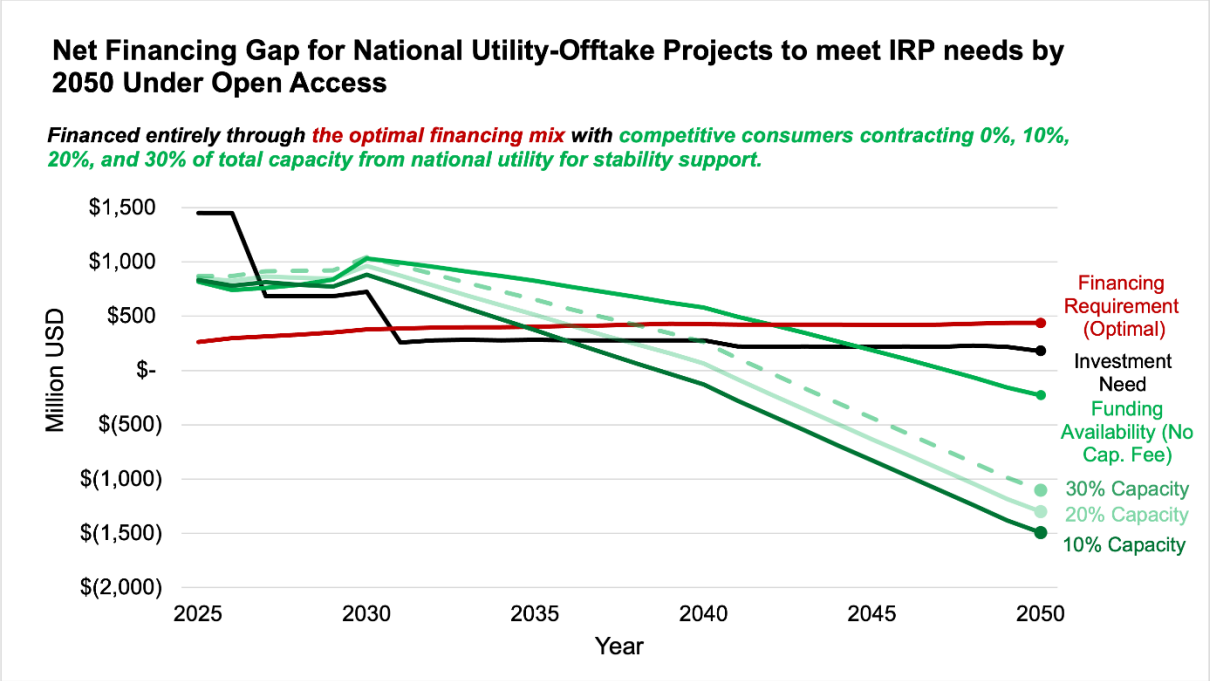

Figure 23. Net Financing Gap Under the Optimal Future Financing Mix and Different Competitive Capacity Shares Under Open Access, 2025-2050 (MINFin).

A combination of 6% nominal regulated tariff growth and competitive consumers contracting 20% of energy needs still doesn't fully close the gap. Figure 24 shows that a financing gap of US$3.9bn still persists after 2040.

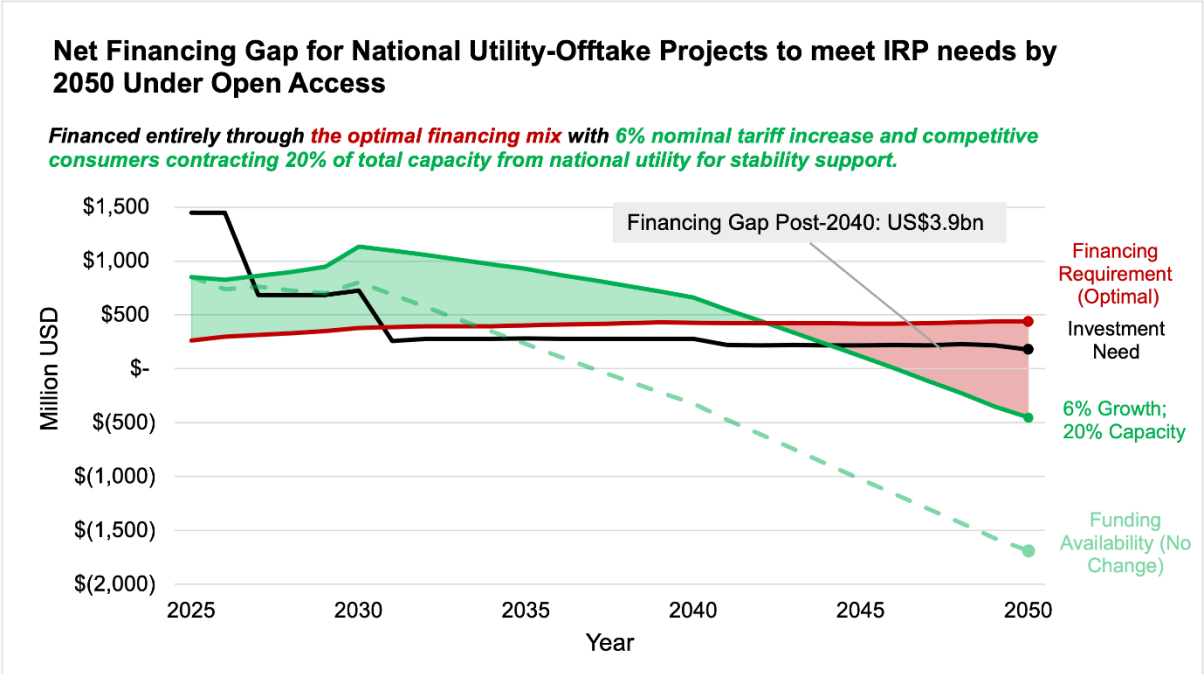

Figure 24. Net Financing Gap Under the Optimal Future Financing Mix, 6% Nominal Tariff Increase, and 20% Capacity Share Under Open Access, 2025-2050 (MINFin).

The design of cost-sharing mechanisms must strike a balance between sustaining market competitiveness and protecting non-contestable consumers from bearing disproportionate costs.

Regulators should consider the possibility of increasing current wheeling costs, capacity fees, and other use-of-system costs to ensure that competitive users who continue to depend on the national utility 's network contribute to full-system cost-recovery. At the same time, it is essential that these adjustments do not undermine market competitiveness.

4.2.3 Recommended Policy Actions

Policy Action 8: *Enhance the flexibility of tariff design for regulated consumers that could include moderate nominal increases, potentially in the range of 4% to 8% per year.*

When the current set of Multi-Year Tariffs expires in 2027, regulators should consider adjustments that enable more responsiveness to fluctuations in market conditions. This may entail a moderate annual tariff increase in the range of 4-8%, with the specific increases differentiated among consumer groups and consumption levels. For instance, within the residential group, lifeline tariff levels should see the smallest increase, while tariffs for the highest consumption bands should align more closely with cost-reflective levels. Table 10 illustrates the average nominal tariffs (in kwacha) for residential and commercial consumers at these growth rates for the five years following 2027.

Table 10. Average Tariff Levels for Regulated Consumers at Different Nominal Growth Rates, 2027-2031 (ZMW/kWh).

Nominal Annual Growth (%)	Consumer Group	2027	2028	2029	2030	2031
4%	Residential	2.60	2.70	2.81	2.92	3.04
	Commercial	1.85	1.92	2.00	2.08	2.16
6%	Residential	2.60	2.76	2.92	3.10	3.28
	Commercial	1.85	1.96	2.08	2.20	2.34
8%	Residential	2.60	2.81	3.03	3.28	3.54
	Commercial	1.85	2.00	2.16	2.33	2.52

Additionally, the following considerations could further enhance tariff equity and responsiveness:

1. *Shorter MYT Review Period*: Given the necessity to implement emergency tariffs due to unforeseen circumstances in 2024, a shorter review period, e.g., three years instead of five, could allow regulators to respond more effectively to evolving market conditions while still providing a measure of predictability for consumers and developers.
2. *Increasing Frequency of True-Up Reviews*: To further enhance responsiveness and align tariffs with actual market conditions, regulators should evaluate the feasibility of shortening the annual true-up reviews to six or nine-month cycles. However, careful consideration of stakeholder concerns and the administrative implications will be vital to ensure that this change is beneficial for all parties involved.
3. *Additional Price Discrimination*: In the absence of a dedicated tariff category for agricultural consumers, their tariffs have been assumed to align with commercial rates for this analysis, following ERB guidance. However, given the expected surge in agricultural energy demand, introducing a new category for agricultural consumers could enhance cost recovery without undermining competitiveness.

Ultimately, the specifics of cost socialisation and tariff design will lie within the domain of the ERB. However, a combination of these measures, subject to prudent considerations, can help increase overall cost recovery while protecting vulnerable groups.

Policy Action 9: *Incorporate long-term system-wide cost recovery considerations alongside competitiveness in transmission price-setting methodologies.*

As the ERB finalises its transparent transmission pricing framework, long-term system-wide cost recovery should be considered alongside objectives to enhance competitiveness and non-discrimination. This includes:

1. *Maintaining a degree of cross-subsidisation within transmission prices* between competitive customers and affordability-constrained domestic customers. Without it, the long-term viability and sustainability of the system could be jeopardised.
2. *Preserving the 3% levy for rural electrification*. Currently, a 3% levy is charged for grid-connected customers, which contributes towards the Rural Electrification Fund (REF) managed by REA, as legally provided under the 2023 Rural Electrification Act [24]. To ensure universal access goals are met, it is critical that this levy is safeguarded during market transition, such as by introducing a similar surcharge on wheeling fees or extending the levy to bilateral contracts. This mechanism is explored further in Chapter 5.

Several supporting activities can help facilitate a smoother transition towards new pricing policies:

1. *Stakeholder engagement and consultation*: All stakeholders, including competitive consumers, non-contestable users, and service providers, should be proactively involved in the development of the pricing methodology to ensure that diverse perspectives are considered and that the framework meets the needs of all parties.
2. *Periodic Review and Adjustment*: Implement mechanisms for regular review and adaptation of the pricing framework to respond to changing market circumstances and technological advancements, ensuring it remains relevant and effective.
3. *Transparency and Educational Initiatives*: Provide workshops to educate the public about the new pricing structure, fostering understanding and transparency in how charges are determined and the reasons behind these changes.

5. Building a Financially Sustainable & Scalable Mini-Grid Pipeline for Universal Access

5.1 Background and Context

In Zambia, rural electrification remains low, and mini-grids are often the least-cost solution for dispersed communities. Only about 34% of rural households have electricity access, and long distances make grid extension impractical [25][26]. Mini-grids, therefore, represent the least-cost solution for many communities.

However, deployment has been hindered by several factors, including inaccurate sizing, unsustainable tariffs, and unreliable demand. A study on five major solar mini-grid initiatives in Zambia revealed that donated systems can undermine willingness to pay, leading to difficulties keeping up with operation and maintenance costs, community-owned systems often lack professional and technical capacity, and seasonal income patterns exacerbate revenue uncertainties [27]. As a result, there are currently only around 53 operational mini-grids in the country [25][26].

The GRZ is scaling up efforts through the recently launched 1,000 Mini-Grid Presidential Initiative, with the goal of reaching universal access by 2030. The initiative is supported by a US$5 million results-based grant delivered through the Zambia Energy Demand Simulation Incentive (ZEDSI) and supported by The Rockefeller Foundation, Global Alliance for People and Planet (GEAPP) and Sustainable Energy for All (SEforALL) [28]. The programme provides performance-based funding to private sector developers while encouraging productive uses of electricity (PUE) and supporting key government agencies with technical assistance. This grant sits within a broader envelope of US$30 million concessional finance and US$108 million grant funding aimed at accelerating mini-grid deployment in Zambia by 2030, committed under the World Bank's ASCENT programme [29].

The LCGEP estimates that expanding mini-grid deployment will require a cumulative investment of US$2.34 billion through 2030. The Least Cost Geospatial Electrification Plan (LCGEP) underpins the IRP's off-grid investment recommendations and identifies the least-cost pathway towards universal access [30]. In parallel, the Rural Electrification Authority (REA), the authority responsible for rural electrification planning and implementation, recently released an updated version of the 2008 Rural Electrification Master Plan (REMP) to reflect demographic changes and the updated access target of reaching universal access by 2030, incorporating and advanced geospatial planning tools [26].

This analysis evaluates the financial viability of both a representative mini-grid and the full pipeline of planned projects within identified resource constraints. Leveraging technical insights and programmatic data facilitated by SEforALL to characterise a portfolio of 1,421 mini-grid opportunities in Zambia, the assessment models a representative 76 kW solar-battery system and its associated aggregate financing needs at the portfolio level. It examines how tariffs, financing structures, and productive use levels affect financial viability under a linear rollout trajectory between 2025 and 2030.

5.2 Strategic Principles and Expected Impacts

Strategic Principle 10: *Prioritise tariff affordability over cost-reflectivity to ensure long-term viability and support the competitiveness of rural productive uses of energy (PUE).*

Achieving cost-reflectivity without subsidies would require tariffs far above what average rural households can afford. For instance, when residential consumers account for 90% of total demand, cost-reflective residential tariffs correspond to approximately 37%, 54%, and 97% of average rural income under high, medium and low load factor sensitivities, respectively, far exceeding the “affordable” benchmark of 5% of monthly income. For reference, the current lifeline tariff for grid-connected residential customers is ZMW 0.54/kWh in 2025, compared to an estimated affordable tariff of ZMW 3/kWh, a more than five-fold increase [4].

In addition to household affordability, maintaining low commercial tariffs is essential for enabling rural PUE growth. Rural PUEs such as milling, agro-processing, cold storage, and other small-scale manufacturing activities, are critical for shifting rural economies away from selling agricultural goods with no value addition. These activities also anchor the commercial demand needed to sustain mini-grid operations beyond the initial few years.

However, current commercial tariffs in operational mini-grids are prohibitively high. Tariffs can be as high as ZMW 13-25/kWh, compared to an average grid-connected tariff of ZMW 1.85/kWh in 2025 and the marginal cost of running diesel generators of around ZMW 7/kWh [33]. When rural businesses face electricity costs far above those paid by grid-connected competitors, the competitiveness of rural PUE erodes, undermining both growth and mini-grid viability.

Strategic Principle 11: *Explore potential mechanisms for supporting mini-grid operating expenses, including the possibility of utilising existing rural electrification funding streams such as the 3% levy on grid-connected consumers.*

Most available grant windows for mini-grids focus almost exclusively on capital expenditure (capex) but provide no mechanisms to support long-term operating expenses (opex). This creates a structural misalignment: while capex subsidies can help accelerate deployment, they do not guarantee the system’s financial sustainability once built. Without stable opex support, mini-grids risk becoming under-maintained, under-utilised, and ultimately becoming a stranded asset. Ensuring that mini-grids function as durable, long-term infrastructure assets, therefore, requires shifting from a capex-only subsidy model to one that also supports ongoing operations and maintenance. This shift would also enable the return on investment to be spread over a longer time horizon, helping to reduce tariffs and improve affordability.

Subsidising operating expenses is essential for full cost recovery, regardless of how the upfront capital investments are financed. Even with full grant funding for capex, current tariff and demand levels are too low to recover ongoing operation and maintenance expenses. One possible avenue that could be explored is the role of existing rural electrification funding streams, including the 3% levy on grid-connected consumers, as a potential source of support for mini-grid operating expenses. Indicative results from the analysis suggest that the scale of estimated future funding flows would be sufficient to support opex coverage. However, the current allocation and utilisation of the levy is not transparent, and the extent to which it could be directed toward opex support would require further policy clarification and exploration, especially as the market shifts toward Open Access.

Strategic Principle 12: *Make PUE development a core requirement of all mini-grid projects to reduce subsidy dependence and ensure long-term financial sustainability.*

A viable long-term business model must incorporate meaningful PUE demand. Rural PUE activities such as agro-processing, refrigeration, milling, water pumping and clean cooking are essential for anchoring commercial demand, driving rural industrialisation, and achieving SDG7: universal electricity access. Modelling results confirm this: operating cost recovery is highly sensitive to demand profiles, with subsidy requirements ranging from near-total dependence under low PUE and commercial demand to almost full recovery under high PUE and commercial demand scenarios.

To achieve this, mini-grid deployment must be paired with deliberate, structured, and mandatory PUE development efforts, including:

- *Ensuring appropriate site selection and accurate system sizing from the outset*. Sustainable operation depends on sizing systems to match peak and expected future demand at the lowest possible life-cycle cost. Evidence from existing mini-grid initiatives shows chronic under- or over-sizing, both of which undermine operational and financial viability [26].
- *Requiring all mini-grid projects to include a dedicated PUE component*. Concession agreements and financing contracts should explicitly incentivise developers to connect PUE customers, undertake market development activities and community training, and actively grow agricultural value chains in their service areas.
- *Strengthening business models that reward PUE uptake and support long-term community engagement*. Approaches such as Pay-As-You-Go (PAYGO) tariff structures, where higher consumption bundles are priced more favourably, can stimulate PUE while maintaining affordability for low-income users.
- *Rural energy cooperative models can also boost local ownership and accountability*, provided they are supported with adequate technical assistance and training.

Strategic Principle 13: *Target a financing structure of 26% grant, 7% concessional debt, and 67% private finance, and cluster projects to attract larger financing and scale delivery.*

Available concessional financing and grant funding earmarked for upfront mini-grid investment is insufficient to finance the full mini-grid pipeline. Under commitments under the World Bank's ASCENT programme, total grant funding for mini-grid expansion is estimated at US$108.42 million and concessional finance at US$30 million over the period 2025-2030 [29]. Taken together, this leaves a financing gap of US$276.6 million against the estimated US$415 million required in upfront capital needed to implement the full project pipeline.

Maximising feasibility will therefore depend on deploying these scarce resources in a way that catalyses and scales private investment, which has remained limited in the sector to date. Distributing the identified grant and concessional finance envelopes proportionally across the portfolio represents the most efficient use of scarce public resources, helping to lower perceived risks and improve overall bankability. This implies a capital structure of 26% grant financing and 7% concessional debt per project, with the remaining 67%, equivalent to US$276.6 million at the portfolio level, mobilised from private sources.

To make this financing structure scalable in practice, projects should be developed and tendered in clusters. Moving from individual site selection to geographically or thematically clustered procurement would increase investor interest, enable larger financing tickets, reduce transaction costs, and improve overall procurement efficiency.

5.3 Recommended Policy Actions

Policy Action 10: *Strengthen tariff guidance under the existing ERB regulatory framework to prioritise affordability and PUE competitiveness, as well as investor predictability.*

Prioritise affordability, PUE competitiveness, and tariff predictability within the ERB's existing regulatory framework. Recent reforms, including Statutory Instrument No. 52 of 2024 have simplified licensing requirements for mini-grids below 5 MW [34], supporting faster deployment and reduced entry barriers. While this improves project viability at the entry stage, it can also increase tariff uncertainty over the longer term, affecting developer confidence and investor participation. To address this, the ERB should consider:

1. *Developing indicative tariff ranges or reference benchmarks* prioritising affordability and PUE competitiveness over full cost-reflectivity, giving developers a clear reference point without rigid caps.
2. *Consider temporary preferential commercial tariff bands for PUE customers* to enhance competitiveness, especially during early stages of adoption.
3. *Introduce a simplified ex-post approval process* for tariffs that fall within published benchmark ranges, reducing regulatory burden while ensuring consumer protection.
4. *Establish a periodic review mechanism* (e.g., every 3-5 years) to update benchmarks and guidance as technology costs, demand profiles, and market conditions evolve.

Policy Action 11: *Explore options to strengthen long-term operational support for mini-grids through mechanisms such as the existing 3% grid levy.*

1. *Consider establishing cross-subsidisation mechanisms for mini-grid opex*. Consider explicitly allowing public funding of opex over long-term horizons (15-20 years) through existing cross-subsidisation mechanisms, recognising that rural electrification delivers public good services similar to grid extension and warrants comparable levels of sustained subsidy. The exact allocation should be revised periodically based on verified opex needs across commissioned sites and may decrease over time as demand grows. This framework should include transparency and reporting requirements on the levy's allocation and utilisation.
2. *Safeguard the sustainability of such mechanisms during market transition* by ensuring they are extended to bilateral contracts under Open Access.

Policy Action 12: *REA should require all publicly supported mini-grid projects to integrate a PUE development component and implement parallel PUE support programmes*

To implement this policy action, two complementary mechanisms are required:

1. *Embed PUE obligations and incentives directly into developer contracts*. Developers receiving public subsidies or concessional finance should be required, subject to prudential measures, to undertake specific PUE development activities. This can be structured through:
    a. *Performance indicators*, such as the number of value-adding enterprises supported;
    b. *Results-based disbursements* that reward PUE load growth;
    c. *Reporting requirements* on demand stimulation activities or value-chain partnerships.

2. *REA delivers parallel PUE support programmes to enable developers to meet these obligations*. Recognising that developers cannot generate rural economic activity alone, REA must provide a supportive environment through complementary public programmes. This includes:
    a. *PUE-specific Results-Based Financing (RBF) schemes* such as ZEDSI;
    b. *Enterprise support* through training, appliance financing, and market development;
    c. *Coordination with agricultural or rural development agencies* to strengthen value chains;
    d. *Technical assistance and socialisation* of communities to ensure sustained uptake of productive appliances.

Together, these parallel mechanisms reduce developer risk, make PUE uptake viable at scale, and ensure that developers view mini-grids as long-term assets rather than short-term infrastructure projects.

6. Summary of Key Strategic Principles and Policy Recommendations

Table 11. Summary of Key Strategic Principles.

Pillar	Strategic Principle	Key Justification(s)	Expected Impact(s)
Pillar 1. Strategic Mobilisation and Deployment of Concessional Finance and Domestic Commercial Finance	**SP1.** Prioritise concessional finance and grant funding for project preparation and technical assistance to bridge early-stage financing gaps.	Feasibility study costs and regulatory fees can often be prohibitively high, hindering projects from progressing to financial close. Local developers and financiers also face capacity constraints in packaging and evaluating energy projects, highlighting the need for dedicated technical assistance.	• Mobilises US$4.7m annually from concessional funding earmarked for project preparation activities, contributing to the estimated US$25m needed to implement the IRP pipeline. • Ensures that a portion of the US$429m in available funds covering both TA and investment support is explicitly set aside for TA needs.
	SP2. In the near-term (2026-2030), a portion of concessional finance should be ring-fenced to provide liquidity support for national utility-offtake renewable projects.	During the transition to a liberalised market under the OAF, the national utility must continue to procure near-term capacity. However, with sovereign guarantees restricted under the IMF ECF, lenders still view national utility-backed PPAs as high-risk.	• The two-tier credit support package, utilising NEAT and other concessional sources, helps restore bankability without sovereign guarantees. • This is expected to facilitate the fast-tracking of 300-400MW of solar projects, with the national utility designated as the off-taker.
	SP3. Prioritise concessional resources and domestic finance for national utility-offtake renewable projects where they have the greatest de-risking impact, while projects procured competitively by large industrial customers should rely primarily on international commercial capital.	Projects serving mining and export customers face lower off-taker and foreign exchange risks, enabling access to cheaper international commercial finance. In contrast, the national utility customers pay in kwacha, eroding long-term cost recovery due to anticipated currency depreciation.	• Allocates scarce concessional and domestic resources to projects with the highest de-risking potential. • Concessional finance directly lowers the WACC, while domestic finance reduces FX exposure, reducing the bankable PPA price for capital-intensive public service assets procured by the national utility, easing the burden on end-user tariffs.
	SP4. Sequence concessional finance mobilisation by targeting the most accessible, high-volume windows first and pursuing more restrictive funds as institutional capacity improves.	Given existing access challenges, funds offering higher volumes with fewer entry barriers, but less concessional terms represent the near-term low-hanging fruit. Over time, more complex or restrictive funds with highly concessional terms can be pursued as project maturity and institutional capacity improve.	See Table 5 for a summary of key fund characteristics in order of prioritisation.

Pillar	Strategic Principle	Key Justification(s)	Expected Impact(s)
	SP5. Leverage the modelled cost premium of climate adaptation of the power system as a clear justification for mobilising targeted adaptation finance.	The IRP's climate adaptation pathway carries a cost premium of US$7bn across 2025-2050, or an average US$152m per year, compared to a business-as-usual pathway where the system continues to rely on drought-prone hydropower.	• Establishes eligibility for climate adaptation funding in project proposals. • Facilitates access to targeted adaptation funding (US$20.3m available annually), plus an additional US$194.7m from funds covering both mitigation and adaptation.
	SP6. Enable domestic financial institutions to participate in large national utility-backed energy projects through light-touch incentives and prudential policy support.	Given mandates with shorter investment horizons, smaller ticket sizes, and lower tolerance for governance risks, domestic investors gravitate toward competitive-market renewables, but this misses where they deliver the greatest system-level impact.	Light, market-compatible policy measures such as fiscal incentives or adjusted investment guidelines for pension funds can nudge domestic capital toward national utility-offtake projects by reducing perceived risks and enhancing bankability.
Pillar 2. Tariff Reform for Fairness and Cost Recovery	**SP7.** Ensure that the socialisation of distribution costs in unbundled tariffs is managed equitably and sustainably.	Sustaining system-wide cost recovery becomes more challenging as services become unbundled. Under Open Access, competitive consumers will only incur charges for transmission services, whereas they previously helped subsidise the distribution network they do not utilise. This means that distribution-related costs will fall entirely on regulated consumers.	As competitive consumers transition to direct procurement, regulators will need to determine how distribution network costs are allocated in a way that is both sustainable and equitable, without overburdening regulated users.
	SP8. A moderate increase in regulated tariffs may be necessary to combat increasing exposure of the national utility's revenue base to foreign exchange risks.	As an increasing share of competitive customers shift toward competitive supply, the national utility's revenue base risks erosion and increased exposure to forex risks. Therefore, along with ensuring that adjustments during true-up reviews can adequately respond to unexpected shocks.	A moderate increase in tariffs will be necessary to mitigate some of these effects. However, increasing regulated tariffs alone won't be enough to close the financing gap when competitive customers completely exit the national utility's revenue base around 2040.
	SP9. *Ensuring domestic tariff affordability and the long-term viability of the sector hinges on maintaining some level of cross-subsidisation through fair and transparent transmission pricing.*	Without maintaining some level of existing cross-subsidisation through transmission pricing for competitive customers, long-term tariff affordability and system viability could be jeopardised. While competitive customers are likely to continue contracting with the national utility to fulfil a portion of its energy needs, this alone won't be enough to close the financing gap.	Regulators should consider the possibility of increasing current wheeling costs, capacity fees, and other use-of-system costs to ensure that competitive users who continue to depend on the national utility's network contribute to full-system cost-recovery. At the same time, it is essential that these adjustments do not undermine market competitiveness.

Pillar	Strategic Principle	Key Justification(s)	Expected Impact(s)
Building a Financially Sustainable & Scalable Mini-Grid Pipeline for Universal Access	**SP10.** Prioritise tariff affordability over cost-reflectivity to ensure long-term viability and support the competitiveness of rural productive uses of energy (PUE).	Given current household incomes and consumption levels, achieving cost-reflectivity without subsidies would require tariffs exceeding affordability benchmarks. This undermines both economic growth and the mini-grid's long-term sustainability.	• Affordable household tariffs promote uptake and retain connectivity for rural residents. • Competitive commercial tariffs maintain the viability of rural PUE, ensuring sustained demand for mini-grid operations beyond the initial few years.
	SP11. Implement cross-subsidisation of mini-grid operating expenses, such as via the existing 3% levy charged to grid-connected consumers.	Most available grant windows for mini-grids focus exclusively on capital expenditure, which can accelerate deployment, but don't guarantee the system's financial sustainability once built. However, subsidising operating expenses is essential for full cost recovery, regardless how upfront capex are financed.	Ring-fencing 30% of the existing 3% grid levy for opex subsidisation would yield roughly US$23,000 per year, enough to cover the average requirement of US$17,500 for a mini-grid commissioned in 2026.
	SP12. Make PUE development a core requirement of all mini-grid projects to reduce subsidy dependence and ensure long-term financial sustainability.	Operating cost recovery of rural mini-grids is highly sensitive to and dependent on PUE uptake for anchoring demand. Thus, a viable long-term business model must incorporate meaningful and sustained PUE demand.	Increasing PUE demand substantially reduces subsidy requirements and eases pressure on tariffs for low-income users, ensuring long-term financial sustainability of the mini-grid.
	SP13. Target a financing structure of 26% grant, 7% concessional debt, and 67% private finance, and cluster projects to attract larger financing and scale delivery.	US$108.4m of available grant funding and US$30 million of concessional finance earmarked for upfront mini-grid investment is insufficient to finance the full pipeline of 1,421 mini-grid projects, which would require US$415m.	• A financing structure of 26% grant, 7% concessional debt, and 67% private finance is the most efficient use of limited resources. • Shifting from individual site selection to geographically clustered procurement improves overall efficiency and enables larger financing tickets.

Table 12. Summary of Key Policy Actions.

Pillar	Policy Action	Key Functions/Steps	Key Institution(s)
Pillar 1. Strategic Mobilisation and Deployment of Concessional Finance and	**PA1.** Strengthen fund-tracking and matching through a centralised unit.	• Monitor fund availability and eligibility requirements across climate and development funds. • Conduct periodic developer interviews and assess alignment with fund-specific criteria. • Match funds with eligible projects in the pipeline, including early-stage project preparation financing.	• **Lead:** Climate Finance Unit (CFU) (forthcoming in 2026) • **Supporting:** Ministry of Energy (MoE), MDBs

Pillar	Policy Action	Key Functions/Steps	Key Institution(s)
Domestic Commercial Finance		• Develop and maintain relationships with core funders.	
	PA2. Set up a dedicated fund to cover early-stage project preparation activities, operating through an open call for applications.	• Pool concessional resources earmarked for early-stage project preparation. • Leverage GRZ budgetary contributions to fill any remaining gaps. • Facilitate competitive access to the fund through periodic calls for applications.	• **Lead:** MoE • **Supporting:** CFU, GRZ
	PA3. Strengthen alignment with the six key eligibility criteria to unlock the majority of concessional finance.	• **Project management:** Require transparent and competitive tendering aligned with the Public Procurement Act (2020). • **Gender & social:** Adopt MoE's Social Safeguards Framework (2024) in project design and implementation. • **Feasibility studies:** Streamline submission processes for developers facing prohibitive fees and delays (*SP3).* • **Debt risk:** Strengthen project-level risk allocation through cost-reflective tariffs and credit enhancement structures *(SP5).* • **Policy** Explicitly link project outcomes to IRP targets, Zambia's NDC, NAP, Green Growth Strategy, among others, in all proposals. • **Climate adaptation:** Use the quantified adaptation cost premium as a core justification for adaptation-aligned funding *(SP2).*	• **Leads:** MoE, CFU • **Supporting:** Energy Regulation Board (ERB), GRZ
	PA4. Institutionalise capacity building for project preparation and fund applications amongst local developers and implementing entities.	Existing and ongoing national initiatives and opportunities: • Centre for Sustainable Energy Modelling (CSEM): forthcoming central hub within the MoE for sustained technical assistance, a national energy data repository, and capacity building on tools such as OSeMOSYS and FINPLAN. • UNZA's MSc in Climate and Energy Modelling (planned for 2026-7): an interdisciplinary programme to train students in energy and financial modelling tools. • CCG's Energy Modelling Platforms (EMPs): quarterly, intensives hands-on training sessions applying open-source modelling tools applied to real datasets and live project contexts.	• **Leads:** MoE, University of Zambia (UNZA) • **Supporting:** CIGZ, CCG
	PA5. Introduce modest fiscal instruments to encourage domestic investment in critical energy projects.	• Reduced or waived withholding tax for domestic debt holders in eligible power-sector infrastructure loans. • Time-bound tax relief on interest income earned from long-term infrastructure bonds.	• **Leads:** Ministry of Finance (MoFNP), GRZ • **Supporting:** Zambia Revenue Authority (ZRA)

Pillar	Policy Action	Key Functions/Steps	Key Institution(s)
		• Targeted corporate tax allowances for financial institutions that allocate a defined share of their portfolio to eligible energy infrastructure investments. • Accelerated depreciation or capital allowances for domestic investors taking equity shares in eligible projects.	
	PA6. Revisit pension investment guidelines and withdrawal rules to expand the investment capacity of public pension funds.	• Revise asset-class caps to allow slightly higher allocations to local infrastructure investments. • Align pension withdrawal rules with infrastructure investment horizons, reducing pressure for short-term liquidity and enabling pension funds to provide longer tenors on infrastructure investments.	• **Lead:** GRZ • **Supporting:** NAPSA, Prudential, etc.
	PA7. Build long-term technical capacity within domestic financial institutions to improve project evaluation, risk assessment, and due diligence of energy projects.	• **Near-term:** leverage external expertise by hiring technical consultants and take advantage of existing TA facilities, which provide support on project appraisal, risk analysis, and financial structuring. • **Long-term:** embed specialised energy-finance expertise internally through dedicated desks/units focused on energy and infrastructure finance.	• **Lead:** Domestic commercial banks • **Supporting:** CFU, MoE
Pillar 2. Tariff Reform for Fairness and Cost Recovery	**PA8.** Enhance the flexibility of tariff design for regulated consumers that could include moderate nominal increases, potentially in the range of 4% to 8% per year.	Consider prudential adjustments that enable more responsiveness to fluctuations in market conditions when the current MYT expires in 2027. This may entail: • Moderate annual tariff increases in the range of 4-8%, with potential differentiation among consumer groups and consumption levels • Shorter MYT Review Period, e.g., three years instead of five • Increasing the frequency of annual true-up reviews • Additional price discrimination within and between domestic consumer groups.	• **Lead:** Energy Regulation Board (ERB) • **Supporting:** MoE, National Utility
	PA9. Incorporate long-term system-wide cost recovery considerations alongside competitiveness in transmission price-setting methodologies.	• Maintaining a degree of cross-subsidisation within transmission prices between competitive customers and affordability-constrained domestic customers. • Preserving the 3% levy for rural electrification. Supporting activities to facilitate a smoother transition towards new pricing policies include: • Stakeholder engagement and consultation. • Periodic review and adjustment.	• **Lead:** ERB • **Supporting:** MoE, National Utility, REA

Pillar	Policy Action	Key Functions/Steps	Key Institution(s)
		• Transparency and public educational initiatives to foster understanding on how charges are determined and the reasons behind these changes.	
Building a Financially Sustainable & Scalable Mini-Grid Pipeline for Universal Access	**PA10.** Strengthen tariff guidance under the existing ERB regulatory framework to prioritise affordability and PUE competitiveness, as well as investor predictability.	• Develop indicative tariff benchmarks prioritising affordability and PUE competitiveness over full cost-reflectivity, giving developers a clear reference point without rigid caps. • Consider temporary preferential commercial tariff bands for PUE customers to enhance competitiveness, especially during early stages of adoption. • Introduce a simplified ex-post approval process for tariffs that fall within published benchmark ranges. • Establish a periodic review mechanism (e.g., every 3-5 years) to update benchmarks and guidance as technology costs, demand profiles, and market conditions evolve.	• **Lead:** ERB • **Supporting:** Rural Electrification Authority (REA)
	PA11. Explore options for strengthening long-term operational support for mini-grids, through mechanisms such as the existing 3% grid levy.	• Consider establishing cross-subsidisation mechanisms for mini-grid opex. Consider explicitly allowing public funding of opex over long-term horizons (15-20 years) through existing cross-subsidisation mechanisms, recognising that rural electrification delivers public good services similar to grid extension and warrants comparable levels of sustained subsidy. The exact allocation should be revised periodically based on verified opex needs across commissioned sites and may decrease over time as demand grows. This framework should include transparency and reporting requirements on the levy's allocation and utilisation. • Safeguard the sustainability of such mechanisms during market transition by ensuring they are extended to bilateral contracts under Open Access.	• **Lead:** REA • **Supporting:** National Utility, ERB, GRZ
	PA12. REA should require all publicly supported mini-grid projects to integrate a PUE development component and implement parallel PUE support programmes.	• Embed PUE obligations and incentives directly into developer contracts. This can be structured through performance indicators, results-based disbursements, reporting requirements on demand stimulation activities or value-chain partnerships, among others. • Introduce public PUE support programmes to enable developers to meet these obligations, including PUE-specific Results-Based Financing (RBF), enterprise support through training, appliance	• **Lead:** REA • **Supporting:** GRZ

Pillar	Policy Action	Key Functions/Steps	Key Institution(s)
		financing, and market development, coordination with agricultural or rural development agencies to strengthen value chains, and socialisation of communities to ensure sustained uptake of productive appliances.	

7. Conclusion

This report presents a detailed financing roadmap that addresses a critical yet underexplored challenge in energy planning: the financial feasibility of national investment plans. The methodology developed and applied here represents a first-of-its-kind approach in Zambia, systematically assessing the plan within the context of existing financing constraints, tariff dynamics, and capital availability at both national and project levels. It provides a practical and replicable approach, alongside open-source tools, for policymakers within the Ministries of Energy and Finance to better coordinate efforts and ensure that national energy plans are not only technically robust but also financially viable.

The analysis examines the financial implications of market transition, an area that is still not fully understood. Given that the sector is in the early stages of the transition toward Open Access, implementation of the IRP was assessed in the context of this shift, highlighting the key considerations and necessary policy actions to facilitate a smooth transition. The results underscore that while the transition may alleviate the national utility's investment and financing burden in the short term, it also introduces risks to its balance sheet in the longer term, as higher-paying customers shift toward competitive supply arrangements.

Under Open Access, the upper-bound financing gap is estimated at US$23bn through 2050, but with strategic deployment of concessional and domestic finance alongside moderate tariff increases, the gap can be reduced to US$5bn. The analysis highlights significant potential to close the gap through strategic finance allocation and innovation, targeted policy interventions, and improved coordination. The scale of investments calls for a decisive shift toward mobilising private capital – one that is already underway in the sector – supported by leveraging a broader mix of instruments such as blended finance, de-risking mechanisms, and local-currency finance. Flexible tariff design, including transparent and equitable transmission pricing, is also critical for ensuring whole-system cost-reflectivity without compromising long-term affordability and sustainability.

Building a bankable pipeline of projects is critical to unlocking both concessional and commercial finance at scale. This will require dedicated institutional support and coordination. Priority actions include establishing a dedicated project preparation fund to cover early-stage costs, leveraging the modelled adaptation cost premium to improve access to climate adaptation finance, and creating a regulatory "one-stop shop" to streamline approvals and reduce bottlenecks. Combined with the broader strategic actions outlined in this report, these measures can help move the IRP from plan to reality.

While this report offers important strategic insights into financing Zambia's IRP, it represents only a starting point. The methodology outlined here was developed and applied to Zambia for the first time, and will therefore require further refinement and testing. Additionally, the tools and models used are still in early stages of development, and further research and collaboration with key stakeholders will be essential to improve their accuracy, usability, and relevance over time.

Finally, while this financing roadmap provides a broad framework, it is grounded in high-level assumptions that need refining through more detailed, context-specific analysis. Further work is needed to examine tariff cost-reflectivity and affordability across consumer groups, incorporating granular consumption and pricing data. At the project level, financial analyses of actual prospective projects, rather than only representative prototypes, will add nuance to assessments of financial viability.

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Appendices

Modelling Assumptions

Table A 1. Assumed Allocation of Generation Technologies between the Public Service Trader (PST) and Competitive Market Under Open Access.

Generation Technology	Typical Output Profile	Assumed Offtaker Under OAF	% Total IRP Investments (2026-2050)	% Total Capacity Addition (2026-2050)
Coal	Baseload	National Utility	8%	9%
Geothermal	Baseload	National Utility	7%	5%
Biomass	Baseload	National Utility	3%	6%
Large Hydro	Baseload	National Utility	17%	16%
Small Hydro	Flexible	Competitive	11%	10%
Solar PV	Variable	Competitive	20%	24%
Wind	Variable	Competitive	32%	29%

Fund and Institution Abbreviations

Table A 2. Fund Abbreviations used in FinTrack Assessment.

Abbreviation	Fund Name
ADB (ADF)	Asian Development Bank (Asian Development Fund)
ADB (OCR)	Asian Development Bank (Ordinary Capital Resources)
ADB (TA)	Asian Development Bank (Technical Assistance)
ADF (PBA)	African Development Fund (Performance-Based Allocation)
ADF (TSF)	African Development Fund (Transition Support Facility)
AF	Adaptation Fund
AfDB	African Development Bank (Climate Commitment)
AIIB	Asian Infrastructure Investment Bank
CAW	Climate Action Window
CTF	Clean Technology Fund
E5P	Eastern Europe Energy Efficiency and Environment Partnership
EBRD	European Bank for Reconstruction and Development
EIB	European Investment Bank
FIP	Forest Investment Program
FIP (DGM)	Forest Investment Program (Dedicated Grant Mechanism)
GCF	Green Climate Fund
GEFF	Green Economy Financing Facility
IDB (GRF)	Inter-American Development Bank (Grant Resources Fund)
IDB (OC)	Inter-American Development Bank (Ordinary Capital)
LDCF	Least Developed Countries Fund
NPC (DGM)	National Project Coordinator (Dedicated Grant Mechanism)
PPCR	Pilot Program for Climate Resilience
PPF	Project Preparation Facility
RPSP	Readiness and Preparatory Support Programme
RST	Resilience and Sustainability Trust
SCCF	Special Climate Change Fund
SGP	Small Grants Programme
SREP	Scaling Up Renewable Energy Program
TF (BD)	Trust Fund (Biodiversity)
TF (CC)	Trust Fund (Climate Change)
TF (LD)	Trust Fund (Land Degradation)
TF (PPG)	Trust Fund (Project Preparation Grant)
WB (IBRD)	World Bank (International Bank for Reconstruction and Development)
WB (IDA)	World Bank (International Development Association)

Table A 3. International Finance Institution Abbreviations used in FinTrack Assessment.

Abbreviation	International Finance Institution Name
ADB	Asian Development Bank
AF	Adaptation Fund
AfDB	African Development Bank
AIIB	Asian Infrastructure Investment Bank
CEB	Council of Europe Development Bank
CIF	Climate Investment Funds
EBRD	European Bank for Reconstruction and Development
EIB	European Investment Bank
GCF	Green Climate Fund
GEF	Global Environment Facility
IADB	Inter-American Development Bank
IBRD	International Bank for Reconstruction and Development (World Bank Group)
IDA	International Development Association (World Bank Group)
IDB	Inter-American Development Bank
IFC	International Finance Corporation (World Bank Group)
IMF	International Monetary Fund
NEFCO	Nordic Environment Finance Corporation
WBG	The World Bank Group

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