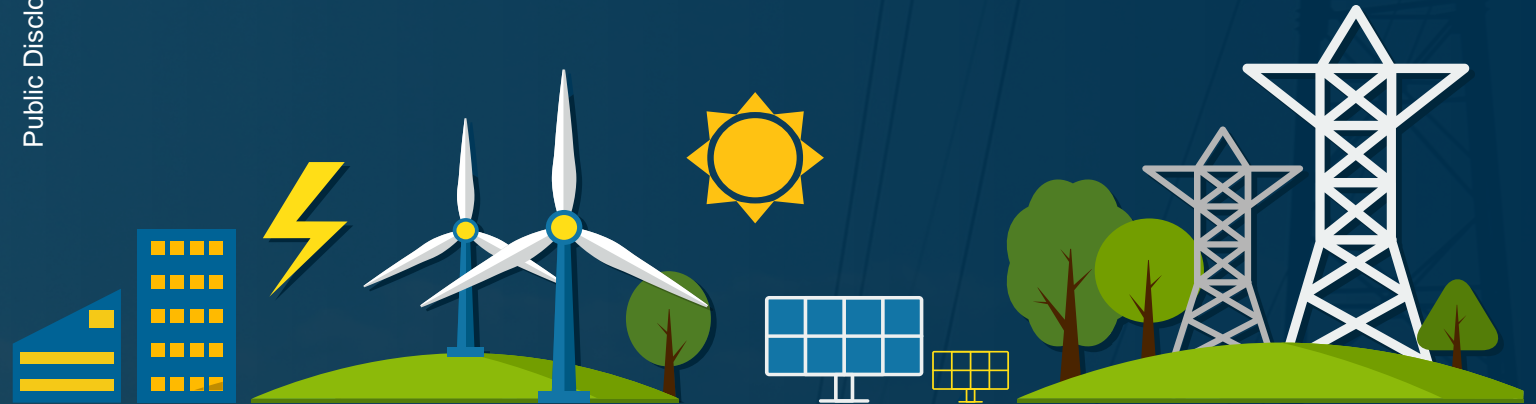




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Executive Summary



The energy transition and universal access to electricity cannot be achieved without well-performing power utilities.

As the stewards of the world's power grids, utilities will be at the heart of efforts to decarbonize electricity supply and electrify energy demand (referred to jointly in this paper as the “energy transition”). Utilities will need to significantly increase the share of renewable energy in their generation mixes, modernize networks to integrate these variable power sources into the grid, and manage the ever-more varied and complex power needs of industry, households, and transportation. In addition, utilities will need to be at the forefront of an accelerated push to provide electricity access to the nearly 700 million people who still lack it today. Meeting these demands while ensuring reliable and affordable electricity service will require well-performing, financially sustainable utilities that i) are able to access inexpensive long-term financing; ii) are viable off-takers for private power investors; iii) make efficient use of any public finance they receive; and iv) have the technological and managerial capacity to harness the opportunities created by an increasingly modern, distributed power system. Although no two countries will be impacted in exactly the same way, these changes will transform power sectors in low-income and middle-income countries (LICs and MICs).

However, utilities around the world are already struggling to deliver affordable and reliable power. A new World Bank database that tracks the financial and operational performance of more than 180 utilities in over 90 countries shows that fewer than

40 percent of utilities are able to collect enough revenue to meet their annual operating and debt service costs—the bare minimum for financial sustainability. This situation is especially bleak for utilities in LICs and lower-middle-income countries (LMICs), where high costs of supply, low tariffs, operational inefficiency, and poor sector planning and procurement often create persistent cycles of underperformance. Technical and commercial losses in power distribution hover between 12 and 15 percent for the median utility in LICs and LMICs, where over half of utilities also have outstanding customer payments equivalent to more than five months of revenue. Utilities that are unable to recover their costs have to make up the shortfall in other ways. Often this results in underinvestment in critical maintenance, upgrades, and system expansion, and increased dependence on government subsidies. Utilities in LICs and LMICs are more likely to rely on such subsidies, adding fiscal burdens to the governments that can least afford to pay them. The data paint a bleak picture and present a stark warning: many utilities are ill-equipped to fulfill their role in achieving the energy transition and universal access.

The energy transition and the push to universal access will create new challenges for utilities, further threatening their performance. For many utilities, achieving the energy transition and universal electricity access will require massive upfront capital investment.

For instance, suitable sites for renewable energy sources such as wind and solar are often far from cities, requiring longer transmission lines to deliver their power to demand centers. Modeling in this paper shows that decarbonizing a hypothetical utility's power supply mix by 2050 could increase the required intensity of its transmission network by 30 percent. Much of this additional capital will need to come from the private sector, but many utilities in LICs and MICs have limited access to private financing and its costs are often prohibitively high. Though a reduced reliance on fossil fuel power can decrease a utility's operating costs over time, these reductions take time to materialize and are often not sufficient to offset higher upfront capital costs. Furthermore, the shift toward greater capital intensity could make utilities more vulnerable to shocks, such as spikes in interest rates. Rising access and electrification of transport and industry will mean that some utilities will also have to contend with rapidly rising demand, which may exacerbate their existing liquidity challenges and make their networks more complex to manage. For other utilities, a growing number of customers using distributed energy resources (DERs) such as rooftop solar could make it more difficult to recover increasing capital costs.

The changing power sector landscape will also create new opportunities to improve utility performance, but utilities that already perform well will be best positioned to seize them. Many utilities, particularly in LICs, are highly exposed to fluctuations in the prices of fossil fuels, which can make costs even harder for utilities to manage. Substituting generation from liquid fossil fuels with renewable generation in line with least-cost planning can help create longer-term price stability for utilities and their customers. DERs and new business models can also create opportunities for proactive utilities to better manage power flows and expand their service offerings to customers. National and international commitments to decarbonization can create additional momentum to lower political barriers to power trade and regional integration, helping utilities reduce their costs and improve network resilience. However, these benefits will not materialize on their own. Attracting investment for new renewable energy sources and for transmission and trade infrastructure requires financially viable utilities that are credible contractual counterparties. To integrate new customer-facing technologies and business models, utilities need the necessary technical and managerial capabilities. At present, too many utilities in LICs and MICs are falling short.

Building sustainable utilities to navigate changing power sector landscapes will require concerted efforts from policymakers, regulators, development financiers, and utilities themselves.



Governments

Governments have a crucial role in lowering the costs to utilities of achieving the energy transition and reaching universal access. They need to create robust policy and legal frameworks that reduce private investors' risk and develop new infrastructure based on least-cost planning and transparent procurement.

Governments

Governments can also minimize complexity in permitting, including for land use for renewable generation and transmission infrastructure. In power sectors that rely heavily on fossil fuels, it will fall to governments to manage sensitivities around phasing down fossil fuel generation and phasing out distortionary subsidies. Public policies and incentives focused on energy efficiency can help mitigate some of the impacts of rapidly growing demand.

02 Regulators

Regulators need to ensure that utilities are able to recover reasonable costs through tariffs, including the costs of achieving universal access and the energy transition. They will also need to adopt innovations in tariff design that efficiently and fairly allocate these additional costs between utilities and their customers. This includes adopting two-part tariffs that enable utilities to recover fixed and variable costs, which will become increasingly important as power sectors become more capital intensive and as more utility customers adopt DERs. Compensation for these grid-connected DERs must reflect the value they add to the system.

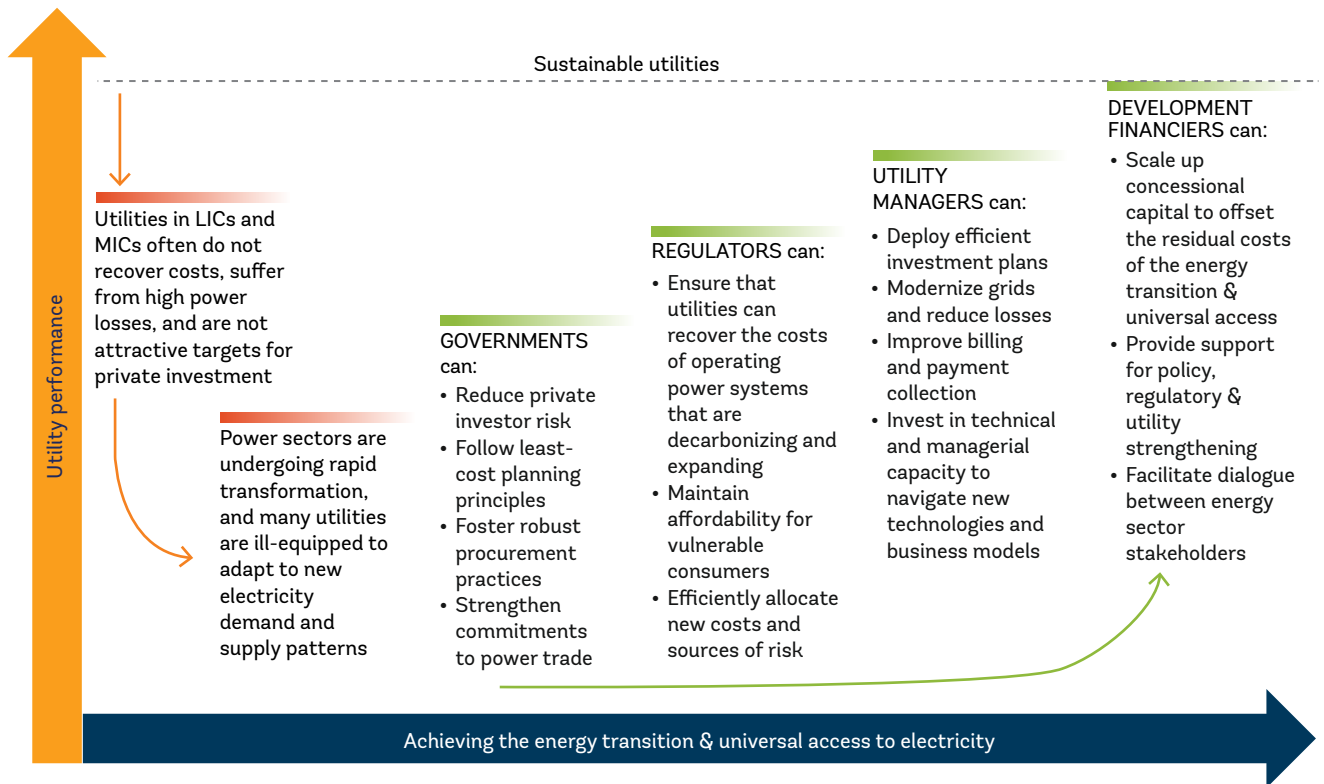
03 Utilities and Utility Managers

Utilities and utility managers need to translate sound policymaking and regulation into sustainable operation of their networks. This will require them to improve their service delivery, reduce their losses, improve their billing and payment collection, maintain and modernize their infrastructure, manage administrative and workforce costs, and invest in managerial systems and capacity. The opportunities presented by the changing power sector landscape will not materialize on their own but must be proactively sought out and developed by utilities. This requires professionally managed, commercially oriented utilities that are governed according to principles of efficiency, transparency, and accountability. To maintain trust and credibility with customers and financiers, utilities need to improve their public communication, including publishing financial statements and operational data in a timely manner.

04 Development Financiers

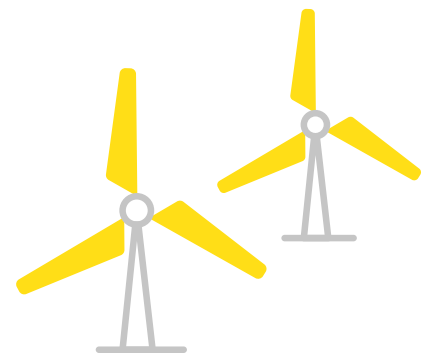
Even if governments, regulators, and utilities all play their part, achieving the energy transition and universal access will create incremental costs for some utilities. Modeling in this paper suggests that a typical utility would require a 1.2 percentage point decrease in its cost of capital to offset the incremental costs of decarbonizing its power supply. Development financiers play a key role in offsetting these costs to keep the energy transition and universal access affordable for LICs and MICs. They can scale up concessional capital that offers longer tenors or lower interest rates compared to commercial financing. And they can reduce private sector investment costs through concessional risk mitigation instruments. At the same time, development financiers need to ensure that any concessional financing is linked to progress by governments, regulators, and utilities in improving the performance of their power sectors. Figure 1 summarizes these actions.

Figure 1: Sustainable utilities for the energy transition and universal access to electricity



The longer these efforts are delayed, the harder it will be for utilities to provide affordable, reliable, and sustainable electricity to their customers. Well-run, well-regulated utilities that operate in transparent, supportive policy environments will be best placed to mitigate the challenges and seize the opportunities presented by a rapidly transforming power sector landscape. These utilities will thrive as they provide clean, secure, and affordable electricity to meet the demands of a growing base of customers with increasingly sophisticated needs. They will also have better access to investment, and at a lower cost. By contrast, utilities that are not able to recover their costs, that operate in

unpredictable political and regulatory environments that are subject to arbitrary interference, and that lack the necessary managerial and technical capabilities, will struggle to maintain affordable and reliable service. These utilities will not only see their performance deteriorate further but will jeopardize national and international targets for decarbonization and universal access. To date, the goals of the energy transition and universal access have received more attention than the importance of utilities in achieving them, especially in LICs and MICs. Filling this gap, this paper aims to serve as an urgent call to action for policymakers, regulators, utilities, and financiers.

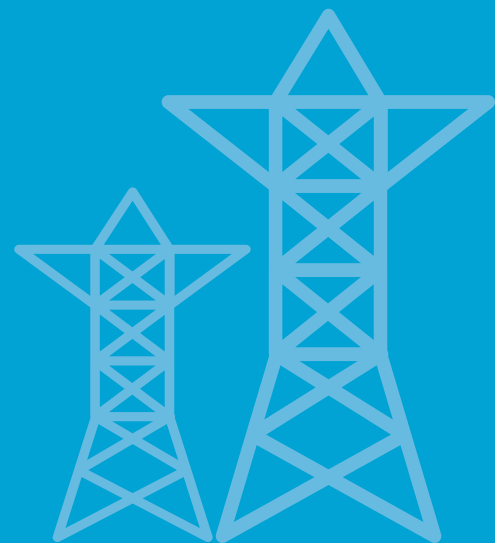




Section 1

Introduction & Methodology

As the conduit between power demand and supply, the utilities that operate the world's transmission and distribution networks will be the critical link in the energy transition.



As the conduit between power demand and supply, the utilities that operate the world's transmission and distribution networks will be the critical link in the energy transition. Utilities will need to expand and modernize their networks to integrate variable renewable energy sources and meet growing demands for cleaner and more flexible power. According to the International Energy Association (IEA), the equivalent of the entire length of the world's grid networks will need to be added or refurbished by 2040 if countries are to achieve their energy and climate goals.¹ As the off-takers of power generation, utilities need to be financially viable to enable the coming massive scale-up of investment in renewable energy projects and grid infrastructure. Utilities will also need to lead the way in providing access to electricity to the nearly 700 million people who still lack it today, mainly in Sub-Saharan Africa. In addition, utilities will need to serve consumers with ever-more varied and complex power needs and an increasing range of distributed generation options, such as rooftop solar. In short, power utilities will be the critical enablers of the energy transition and achieving universal access. This paper aims to place the need for sustainable utilities in lower-income countries (LICs) and middle-income countries (MICs) at the heart of the energy sector dialogue.

The focus of this paper is on the utilities that manage power transmission or distribution grids. This includes the

standalone (unbundled) utilities that are responsible for the transport of bulk power on high-voltage lines (“transmission”); the utilities that are responsible for carrying power to end-consumers (“distribution”); and the vertically integrated utilities (VIUs) that also own and operate power generation assets.² These utilities ensure that generated power finds its way to the residential, municipal, commercial, and industrial uses of power that underpin modern economies. They are responsible for planning and investing in grid and grid-related infrastructure; they ensure the system's smooth functioning and reliability by maintaining a constant balance between power supply and power demand; they serve as off-takers for power generation; and they act as the interface between the power sector and consumers, providing customer connection, billing, metering, and payment collection services. For this paper, collectively, these utilities are referred to as “network utilities,” “power utilities”, or just “utilities.”

The analysis and recommendations in this paper draw extensively on new data in the World Bank's Utility Performance and Behavior Today (UPBEAT) database.³ UPBEAT is a unique database that captures the financial and operational performance data of over 180 utilities in over 90 countries around the world from 2012 to 2022 (Figure 2).⁴ Forty-one of these utilities (or about 25 percent) are privately owned. A total of 112 utilities are in LICs and lower-middle-income countries (LMICs) and 70 are in upper-middle-income countries (UMICs) and high-income countries (HICs).⁵

1 - IEA. 2023b. “Electricity Grids and Secure Energy Transitions: Enhancing the Foundations of Resilient, Sustainable and Affordable Power Systems.”

2 - This excludes utilities such as state-owned generation enterprises or private independent power producers (IPPs), whose sole commercial activity is power generation.

3 - The full UPBEAT database can be accessed at utilityperformance.energydata.info.

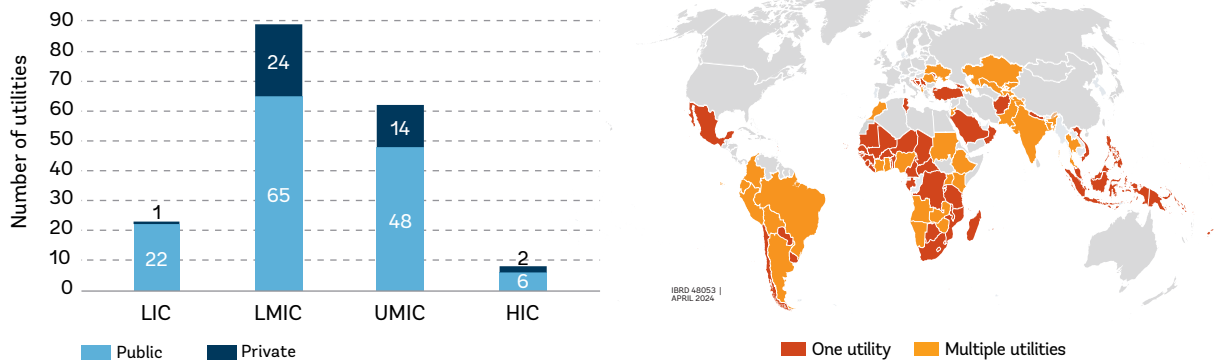
4 - Utilities were selected based on data availability and the presence of past or ongoing dialogue with the World Bank. Therefore, the database does not purport to be representative either at the national or the global level.

5 - To mitigate small sample sizes, much of the analysis in this paper groups LICs with LMICs, and UMICs with HICs.

UPBEAT processes the financial and operational data published by utilities, regulators, and other energy sector entities into a set of standardized indicators. This enables UPBEAT to provide utilities, policymakers, financiers, investors, and researchers with uniquely detailed insight into power utility performance across the world.

One persistent performance challenge is that financial statements and annual reports are often published several years after the close of the financial year, if they are published at all. Thus, unless otherwise specified, analysis in this paper considers the most recent available data point from 2020 onwards.

Figure 2: Number of utilities in the UPBEAT database by country income and ownership (left), and geographic distribution (right)



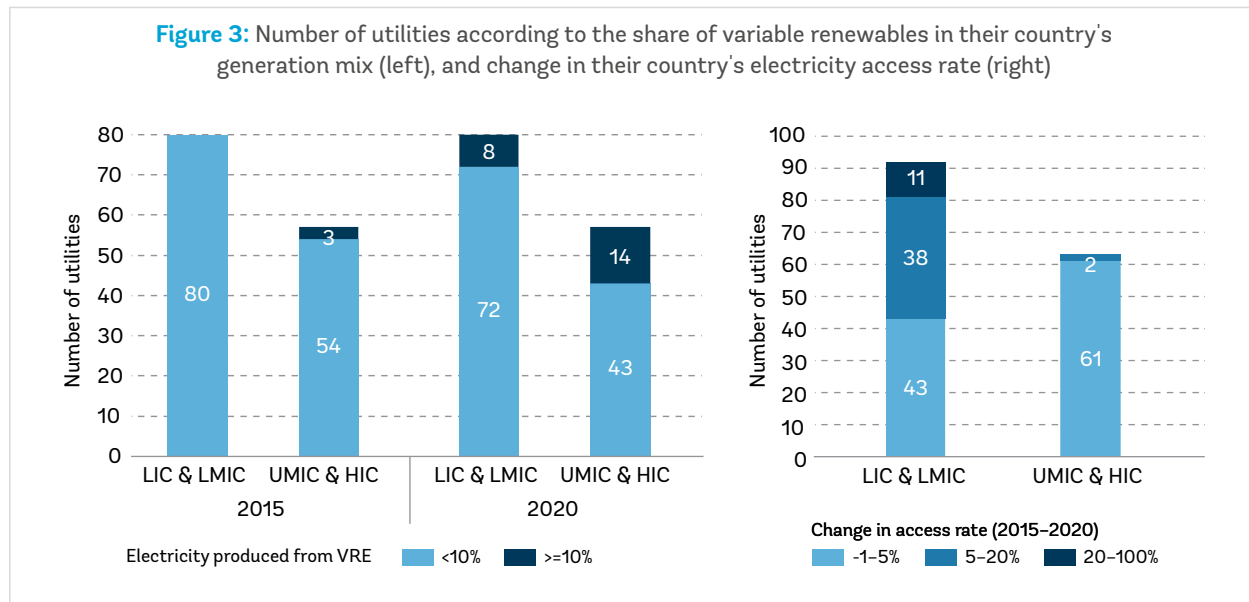
This paper builds on previous World Bank efforts to measure and understand utility performance. The 2019 report, *Rethinking Power Sector Reform in the Developing World*, which examined utility performance in 17 developing countries, found that many utilities were operating in countries with weak regulation, inadequate provisions for tariff adjustments, no technically grounded plans for generation expansion, weak contractual frameworks for power purchase agreements (PPAs), and high system losses. These utilities were struggling to recover their costs, and they were often forced to adopt a range of suboptimal coping strategies, including taking on high-cost, short-term commercial debt, or falling into arrears with their upstream suppliers of fuel or power. Building on these findings, the World Bank's 2021 study, *Utility Performance and Behavior in Africa Today*, undertook a comprehensive survey of utilities

in Sub-Saharan Africa and found that only one in three utilities were able to recover both their operating and debt service costs, even when accounting for operating subsidies utilities received from their governments. Most recently, the World Bank's 2023 paper, *Scaling Up to Phase Down: Financing Energy Transitions in the Energy Sector*, identified utilities as potentially the "weakest link" in the energy transition.

In most LICs and MICs, the energy transition is still at an early stage. Very few of the utilities analyzed for this paper operate in countries where variable renewable energy sources such as solar and wind already constitute a large share of the generation mix. While many more countries have reached universal access than have met their decarbonization goals, this was often achieved decades ago or over a long period.

Figure 3 shows that only a few of the utilities in the UPBEAT database operate in countries with a variable renewable energy (VRE) share that is greater than 10 percent⁶ or that have achieved high growth in their electricity access rates between 2015 and 2020. To better

illustrate the prospective future impacts of the transition on utilities, this paper complements the historical data from UPBEAT with forward-looking simulations and country examples.



This paper is organized as follows:

Section 2 provides an overview of current and historic utility performance challenges in LICs and MICs. It argues that many utilities are struggling to operate sustainably and are poorly prepared for the demands of the energy transition.

Section 3 explores how the changing power sector landscape will present new challenges and opportunities for utilities and utility performance.

Section 4 discusses the actions that policymakers, regulators, development financiers, and utilities can take to build resilient utilities able to navigate an evolving power sector landscape. It also provides a rationale for additional concessional finance for utilities.



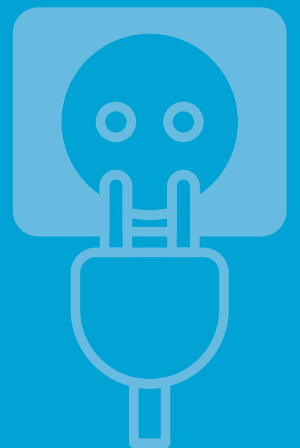
6 - As generation data were not obtainable at the utility level for a sufficient number of utilities, this paper considers generation data at the national level, which were drawn from the IEA World Energy Balances database.



Section 2

Historic and Current Global Utility Performance

Utilities around the world are underperforming, especially in LICs and LMICs.



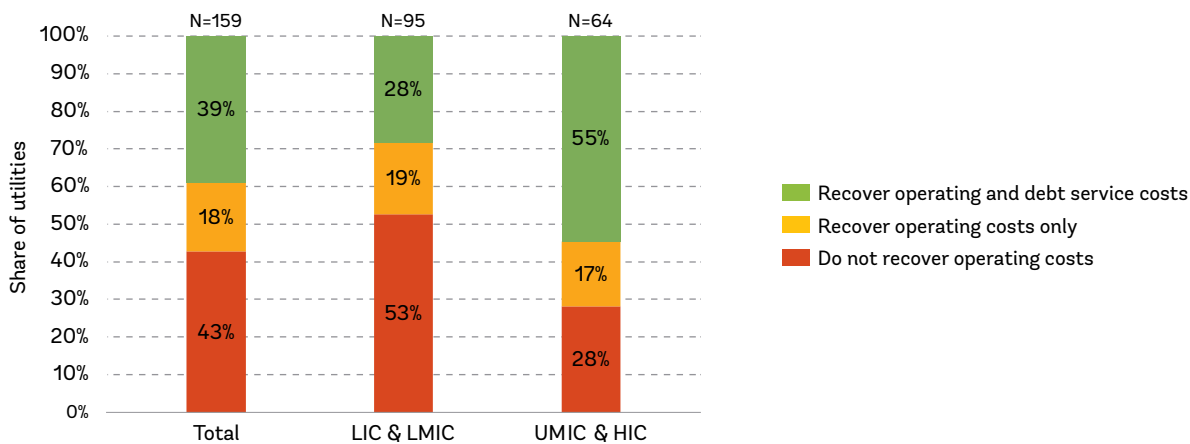


Most utilities do not recover their operating and debt service costs; utilities in LICs and LMICs perform significantly worse than utilities in UMICs and HICs.

Financial viability is a challenge for most utilities, with less than 40 percent⁷ recovering both their operating and debt service costs.⁸ Low cost recovery is often at the heart of a vicious cycle of utility underperformance: insufficient recovery of costs deprives utilities of the funds they need to invest in infrastructure and maintenance; this, in turn, leads to higher system losses and more frequent and longer outages; and declining service quality may make regulators and policymakers less willing to adjust tariffs, further depriving utilities of the funds they need. Figure 4 shows the proportion of

utilities, worldwide, that recover their operating and debt service costs (green bar), that recover only their operating costs (orange bar), or that cannot even recover their operating costs (red bar). Overall, 39 percent of utilities are able to recover both operating and debt service costs, another 18 percent are able to recover operating costs only, and over 40 percent do not recover their operating costs. Utilities that do not recover costs present greater risks to investors, will face higher financing costs, and will struggle to attract financing at the scale required to achieve the energy transition and universal access.

Figure 4: Share of utilities by country income that are fully recovering both their operating and debt service costs (green bar), their operating costs only (orange bar), and neither their operating nor their debt service costs (red bar)



Utilities in lower-income countries are significantly less likely to recover their costs than utilities in higher-income countries.

The UPBEAT data show a striking difference in utilities' abilities to meet their financial obligations, depending on the income level of the country where they operate.

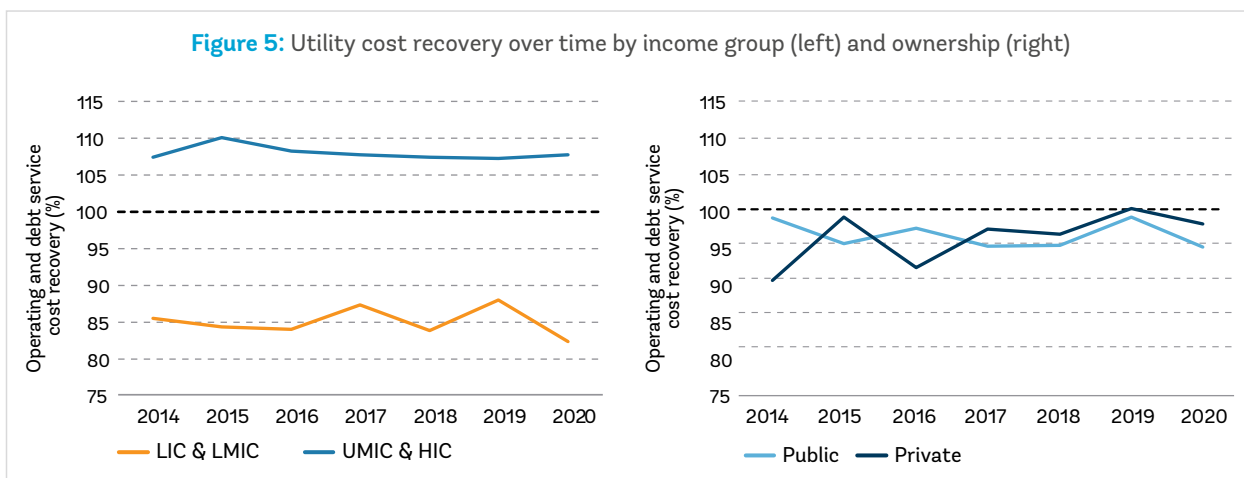
7 - Statistics on utility performance in this paper refer to the utilities included in the UPBEAT database.

8 - Cost recovery here refers to the extent to which the payments a utility collects from its customers cover the costs it reports in its financial statements, compared to, say, efficient costs determined by a regulator.

More than half of utilities in LICs and LMICs included in UPBEAT do not collect enough revenue to recover even their operating costs, and only 28 percent are able to recover both their operating and debt service costs. Conversely, 55 percent of utilities in UMICs and HICs recover both their operating and debt service costs, and another 17 percent recover at least their operating costs. These differences are persistent over time (Figure 5,

left-hand panel). Between 2014 and 2020, the median utility in UMICs and HICs consistently recovered both its operating and its debt-service costs, while the median utility in LICs and LMICs recovered less than 90 percent of its debt service and operating costs.⁹ The data also show that private utilities slightly outperform public utilities, though the difference is small (Figure 5, right-hand panel).

Figure 5: Utility cost recovery over time by income group (left) and ownership (right)



Utilities' poor cost recovery results from their costs being too high, the tariffs they charge being too low, high losses in transmission and distribution, and poor collection of customer payments.

Cost recovery requires a utility to generate enough cash from electricity sales to meet its costs of supply. Three factors determine its ability to do this: i) the magnitude of its operating and debt service costs relative to the tariffs it can charge; ii) how much of the electricity it buys or generates it can bill to customers compared to how much it loses in transmission and distribution lines or to theft and poor metering practices; and iii) its ability to collect payments from its customers. Utilities in LICs and MICs often underperform on all of these factors.

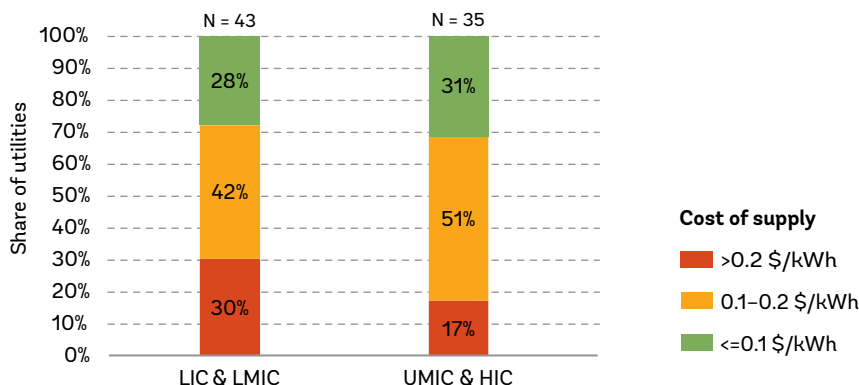
Many utilities face a mismatch between their costs of supplying power and what they are able to charge customers. Utilities' costs of supply may be inherently higher in some countries due to differing natural endowments in generation resources, but in LICs and MICs, this is often exacerbated by poor planning, uncompetitive power procurement practices, high and volatile costs of imported fuel and other inputs, administrative inefficiencies, and high capital costs.

9 - In general, this paper presents data on median values only up to 2020. This was necessary to avoid panel balancing issues, as utilities with more recently available data tend to perform better on financial indicators.

In poorer countries, these elevated costs can be particularly difficult to pass on to customers, many of whom cannot afford to pay much for electricity. These customers also tend to be those for whom electricity is a

larger share of their household budget, despite consuming very little. Figure 6 shows that utilities in LICs and LMICs are more likely to face high costs of supply of over 20 cents per kWh.¹⁰

Figure 6: Share of utilities by cost of supply and country income¹¹



Many utilities' ability to recover costs is further diminished by power lost in network components (technical losses) or lost to theft and poor metering and billing practices (commercial losses).

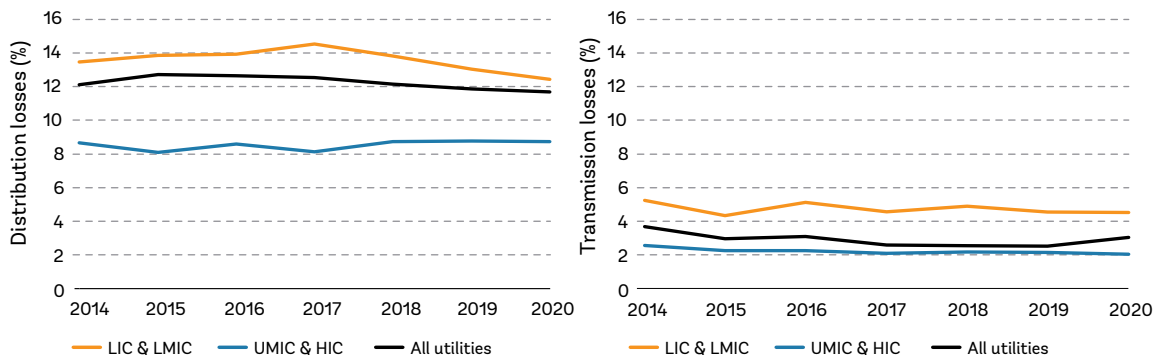
Even for utilities that are able to charge cost-reflective tariffs, cost recovery still depends on how much of the power they buy or generate reaches and is billed to end consumers. The UPBEAT data show that utilities in countries of all income levels lose significant portions of their power, especially in distribution, where the median utility lost around 12 percent of its power between 2014 and 2020 (Figure 7, left-hand panel). Such losses are particularly a challenge for utilities in LICs and LMICs, where distribution losses are significantly higher than in UMICs and

HICs. Losses are lower across the board in transmission due to the technical nature of high-voltage power transport and the lower potential for theft or underbilling, but are still significantly higher for utilities in LICs and LMICs (Figure 7, right-hand panel). High transmission losses are typically the result of underinvestment and overloading of transmission lines, and may present significant bottlenecks to the greater power flows that utilities will need to handle under the energy transition.

10 - Dollars and cents in this report are United States dollars.

11 - This excludes transmission-only utilities, many of which do not include generation in their costs.

Figure 7: Median distribution losses (left) and transmission losses (right)

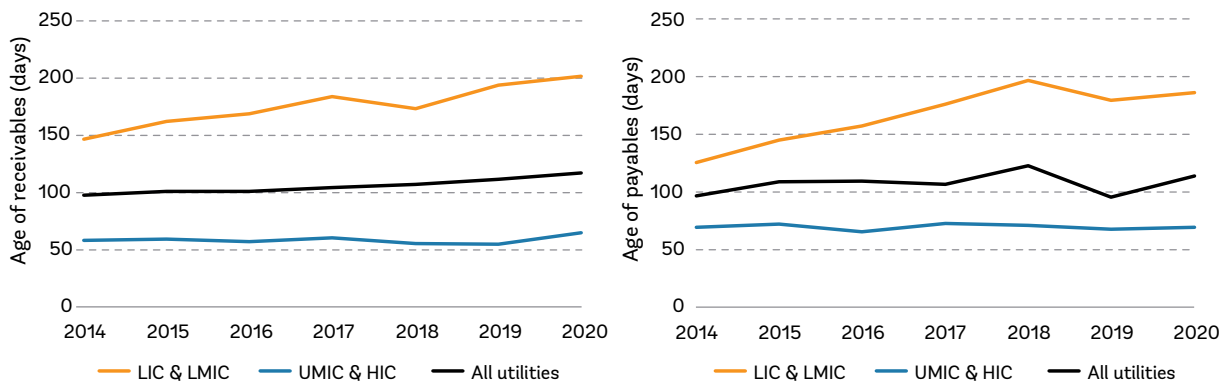


Finally, cost recovery requires that utilities convert electricity bills to cash by collecting payments from customers.

Few utilities are able to do this efficiently, and as a result, they have high levels of uncollected customer payments. Over half of utilities in LICs and LMICs have outstanding customer payments (receivables) equivalent to more than 150 days of revenue,¹² compared to only 20 percent of utilities in UMICs and HICs. Delayed or inconsistent payments for electricity by public sector customers, such as government offices, publicly owned mines, or water utilities, often make up a disproportionate share of receivables. Concerningly, the receivables of utilities in LICs and LMICs have been steadily

growing over time (Figure 8, left-hand panel). Poor collection performance, especially by distribution utilities, is often felt across the power sector because poor collection means that less cash is available to pay upstream generation and transmission utilities. Accordingly, the UPBEAT data show that over 60 percent of utilities in LICs and LMICs have outstanding payments to suppliers (payables) equivalent to over 150 days of costs.¹³ For many utilities, these payables include delayed payments to independent power producers (IPPs), which often result in penalties or costly contractual disputes and act as a deterrent for future investment. As with receivables, the payables of utilities in LICs and LMICs (Figure 8, right-hand panel) have been increasing.

Figure 8: Median age (in days) of utility receivables (left) and payables (right) over time



12 - This can be understood as the average time it takes a utility to collect payments from customers, weighted by the amount of the payment.

13 - This can be understood as the average time it takes a utility to pay its suppliers, weighted by the amount of the payment.



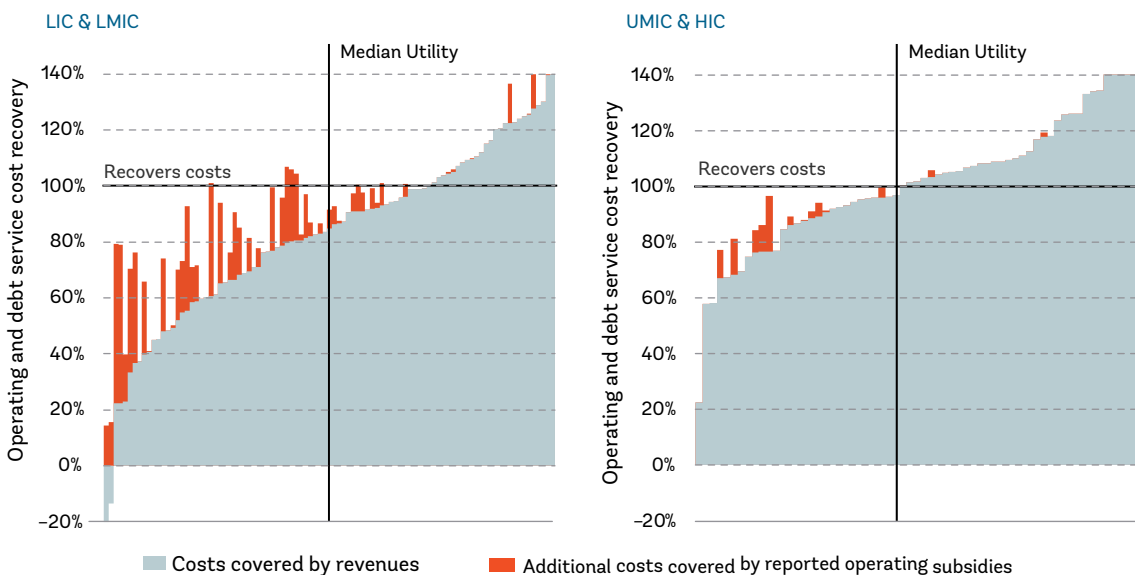
Public finance is often used to cover gaps in cost recovery, but public investment may be more efficiently spent on improving utility performance.

Poor cost recovery has implications beyond a utility's financial performance, especially in LICs and LMICs.

Utilities that struggle to recover their costs are more likely to receive government subsidies, which often place a significant burden on public finances. Figure 9 shows the impact of government operating subsidies on utilities' ability to recover their costs.¹⁴ In general, operating subsidies are more likely to be reported by utilities that do not recover their costs, and these utilities are predominantly in LICs and LMICs. Thus, the countries that can least afford it are the ones that are most likely to be using public finances to make up for their utilities' revenue shortfalls.

Governments may choose to subsidize electricity tariffs using public funds because consumers are often highly sensitive to fluctuations in electricity prices, which are immediately noticeable. In contrast, the specifics of how governments allocate public budgets to these subsidies are less visible and may draw less public scrutiny. However, these subsidies often perpetuate utility inefficiency.¹⁵ They can also be regressive in countries with low access to electricity, where poorer taxpayers who are not connected to the grid may subsidize the power consumption of the more affluent consumers who are.

Figure 9: Utilities that do not recover costs are more likely to receive subsidies



14 - Utilities receive government subsidies in a variety of ways, including direct transfers from government, government-financed reductions in the cost of fuel or other inputs, favorable tax treatment, or vouchers or transfers to consumers to pay for electricity. This analysis only considers transfers from governments reported in utility financial statements.

15 - For instance, research suggests that utilities in some cases may prefer revenue from subsidies to revenue from sales, and that subsidies disincentive utilities to improve operational performance (McRae, 2015).

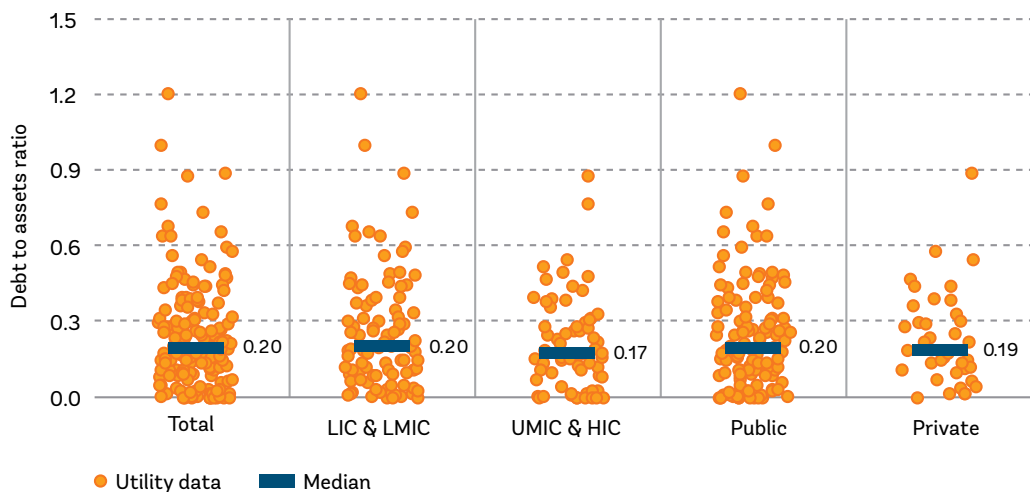


Utilities have relatively little debt on their books and often finance themselves through other liabilities, which suggests that many utilities face capital constraints.

Utilities carry relatively low levels of formal debt on their books. For the median utility, only about 20 percent of the assets on its books are financed with debt, with the remainder coming from equity or other liabilities (Figure 10). There is relatively little difference in median indebtedness between public and private utilities and between utilities in different country income groups. Public utilities and utilities in LICs and LMICs, however, are more likely to have large amounts of debt on their books (but also more likely to have very low debt). This could have a range of explanations. Private utilities may have better access to equity financing, may be subject to

greater financial discipline, and may be more likely to be part of holding company structures that hold debt on behalf of subsidiary utilities. Public utilities, in turn, may have easier access to financing in LICs and MICs through sovereign borrowing. Some utilities in LICs and LMICs may require additional debt to make up funding shortfalls; they may have greater relative investment needs to meet rising demand; or they may have more debt denominated in foreign currency and thus be more vulnerable to devaluations that increase their debt burdens. Utilities in LICs and LMICs also face more expensive debt, even though they are more often publicly owned.

Figure 10: Utility indebtedness is relatively low across the board, with little difference by country income or utility ownership

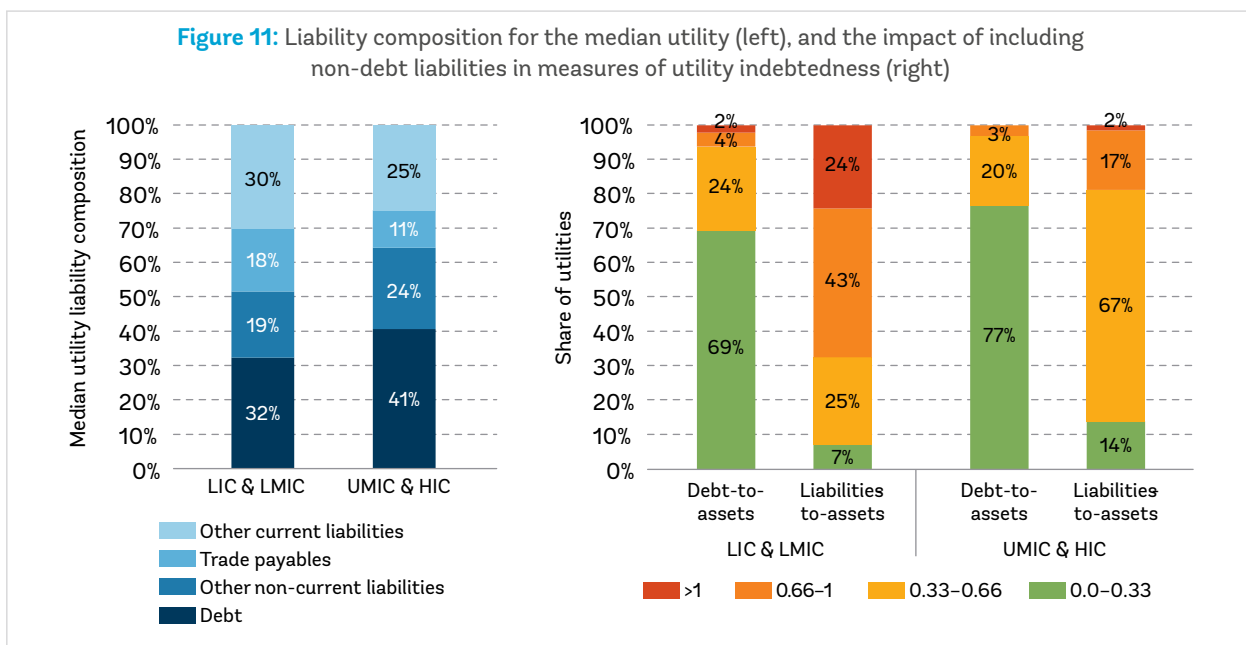


However, formal debt may be underestimating utilities' indebtedness. Debt from commercial lenders, development

banks, or other credit facilities accounts for around 35 percent of the liabilities on the balance sheet of the median utility (Figure 11, left-hand panel).

The remainder comes from other liabilities such as unpaid financial obligations for taxes or power, unrendered services for payments received (for example, taking a long time to connect new customers even after they pay their deposits), or longer-term liabilities such as pension obligations or leases. These liabilities can behave almost like debt as they constitute future payment obligations—in some cases with interest-like costs or penalties attached to them—but are not classified as debt in

utilities' books. Taking these additional liabilities into account suggests that many utilities' effective level of indebtedness may be higher than what is implied by their loans alone, especially in LICs and LMICs (Figure 11, right-hand panel). While it is difficult to identify absolute thresholds for what constitutes “too much” or “too little” debt, almost a quarter of utilities in LICs and LMICs have liabilities that exceed their assets, meaning they have negative equity and are balance sheet insolvent.



When they do carry debt, many utilities, especially those in LICs and LMICs, already benefit from some concessionality in loan pricing.¹⁶ This concessionality could result from several factors, including access to development finance or other concessional capital, public ownership, or public backing of utilities that allows them to borrow at, or near, sovereign rates. While utilities in LICs and

LMICs face higher costs of debt (Figure 12, left-hand panel), they also benefit from greater discounts on their debt compared to sovereign rates (which are typically higher in lower-income countries due to higher perceived credit risk). Over half of the utilities in the UPBEAT database have effective interest rates that are below estimated sovereign rates (Figure 12, right-hand panel).¹⁷

16 - Concessionality in this case is determined by the difference between the effective interest rate a utility pays on its debt, and the pricing of the country's sovereign debt. Sovereign financing costs are estimated using United States Treasury rates and country risk premiums (source: Country Risk Determinant, Measures and Implications, Stern School of Business New York University).

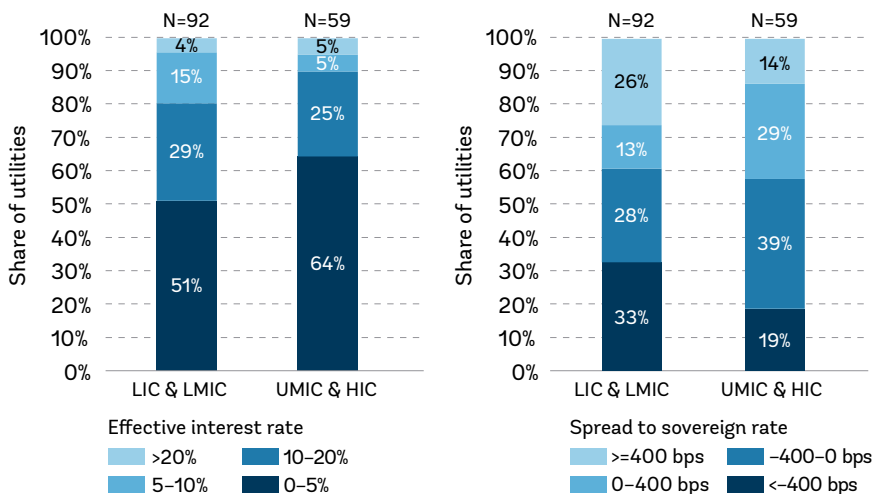
17 - Effective interest rates are calculated as a utility's interest expense divided by its stock of debt.

Another 20 percent of utilities report financing costs that are less than 400 basis points above sovereign rates, which in many cases may still be well below their commercial borrowing costs. Utilities in countries of all income levels benefit from concessionality, but utilities in LICs and LMICs are more likely to report effective interest rates that have the highest degree of concessionality.

The relatively low levels of debt on utilities' books and the widespread presence of concessional financing suggest that many

utilities are struggling to access or afford non-concessional loans. These capital constraints do not bode well for utilities' ability to access new debt to finance capital expenditures in renewable energy generation, grid expansion and modernization, and other infrastructure investments that will be required by the energy transition. Conversely, utilities that are able to mobilize additional private capital for transition-related investments may see significant increases in their costs of capital if they have relied heavily on concessional financing in the past.

Figure 12: Share of utilities by effective interest rate (left) and spread of the effective interest rate against the sovereign rate (right)

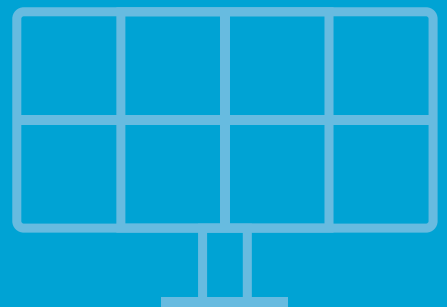




Section 3

New Challenges and Opportunities for Utility Performance

Upcoming changes to the supply and demand of power will disrupt decades of business as usual for network utilities in LICs and MICs.



Upcoming changes to the supply and demand of power resulting from policy choices and technological developments will disrupt decades of business as usual for network utilities in LICs and MICs. Well-performing utilities will be critical for achieving decarbonization and universal

access but progress toward these goals, and new trends in the power sector landscape will, in turn, present new challenges and opportunities for utility operations and utility performance. This section highlights some of the most important new forces that will affect utility performance in LICs and MICs, specifically:



- Increased utility capital intensity as a result of VRE integration and network expansion
- Reduced utility operating cost volatility as a result of declining shares of fossil fuel power in generation
- Changing demand patterns resulting from higher electricity consumption and the greater availability of alternatives to grid power
- New business models and digital tools for utilities to better manage their grids and expand their service offerings

These trends will not impact all utilities equally or at the same time. Decarbonization and electrification of demand may, at least initially, be more pressing concerns for utilities in countries with well-developed power sector infrastructure, while utilities in countries with extensive power infrastructure gaps may prioritize reaching universal access. Nonetheless, the effects described are relevant for utilities across geographies and levels of development: utilities in LICs are also

facing increasing incentives to decarbonize; distributed energy resources (DERs) will be an attractive alternative to grid power both for consumers in more affluent countries who want to achieve cost savings, or improve their carbon footprint, and for consumers in poorer countries who need alternatives to unreliable grid service; and transmission investments to integrate VRE, and distribution investments to add new connections, will both require utilities to take on additional capital.



The shift from fossil fuels to renewable generation and the push to universal access will increase utilities' capital intensity, exposing them to new risks.

Maintaining service quality amid dramatic shifts in the demand and supply of power will require utilities to make massive new investments. Integrating geographically dispersed renewable energy sources will require investing in larger and more resilient

transmission networks. The variable and uncertain nature of wind and solar energy means that more installed generation capacity and more associated network infrastructure are required to deliver the same amount of power.

This is because land-use constraints often mean that developable solar and wind resources are located farther from load centers, so more lines must be built to transport a given amount of power. Increasing power consumption due to the electrification of energy demand in industry and transport will require further investments in transmission and distribution capacity to avoid grid congestion and maintain service

quality. In LICs, achieving universal access targets will require utilities to finance additional connections and strengthen their transmission and distribution networks to support a growing grid. Investment will be required not just to address these impacts, but also to ensure that new and existing infrastructure is resilient to climate shocks such as forest fires, storms, and floods. Box 1 shows the effects of this increased capital intensity on a hypothetical utility.

BOX 1

Simulating higher capital intensity for a hypothetical utility

The impacts of the energy transition on utility capital intensity are simulated here for a hypothetical utility. This utility is based on a stylized composite of utilities in LICs and MICs. The utility is assumed to be vertically integrated (responsible for generation, transmission, and distribution) and operating in a well-functioning regulatory environment that allows the utility to recover its costs through annually updated tariffs. As a result of the energy transition and increasing access to electricity, the hypothetical utility needs to: i) deal with higher demand; ii) build and integrate into the grid a greater amount of generation capacity to meet this higher demand; and iii) reduce the share of fossil fuel plants in its generation mix in favor of renewable technologies.

The energy transition leads to a significant increase in the capital intensity of the hypothetical utility. Table 1 shows the evolution of demand and supply for the hypothetical utility (Table 1, rows 1 and 2), both of which are significantly higher in the *with-transition* scenario than in the *without-transition* scenario. The supply mix in the *with-transition* scenario includes a higher share of VRE, notably wind and solar, which is characterized by higher upfront capital costs but lower ongoing operating costs when compared with fossil-fuel-based generation. The higher share of wind and solar energy in the generation mix also leads to a need for more transmission infrastructure to transport the same amount of demand. As a result, transmission intensity (measured here in kilometers of transmission line per unit of demand served) for the hypothetical utility is considerably higher in the *with-transition* scenario (Table 1, row 3). These factors cause the size of the utility's asset base to increase (Table 1, row 4).

Table 1: Demand, supply, transmission intensity, and cost structure for the hypothetical utility without and with the energy transition

Parameter	2025	2050	
	Base	Without transition	With transition
1. Consumption (TWh)	100	185	275
2. Share of generation from VRE	15 percent	25 percent	85 percent
3. Transmission line intensity (length of line per unit of demand, normalized to 100)	100	105	130
4. Size of asset base (normalized to 100)	100	190	270

These investments will make utilities more capital intensive, thereby altering their exposure to certain performance risks. In the near term, one of the main challenges for utilities in LICs and MICs will be to access sufficient affordable financing for these investments. However, even if sufficient public and private capital is made available to these utilities, as it will have to be for the energy transition to succeed, an increase in capital intensity could exacerbate utilities’ exposure to several sources of performance risk, including i) higher costs of capital as utilities that have depended on concessional capital in the past take on more private financing; ii) greater exposure to long-term volatility in costs of capital; iii) a move toward longer-term and thus, typically, more expensive debt; iv) less flexibility in utilities’ cost structures as their share of fixed costs increases, which may, for instance, make it more difficult for utilities to deal with short-term demand shocks; and v) a greater value of utility assets that may be at risk of impairment—for example as a result of policy changes or changes in consumer behavior (see Box 2 for a simulation of the impacts of selected shocks on utility performance).

The investments required to decarbonize generation will affect even network utilities that do not own generation assets. Network utilities will need to invest in additional transmission and distribution capacity to integrate VRE, as discussed above. But network utilities will also feel the effects of increased capital intensity in power generation, even if they do not own any generation assets themselves. Network utilities that buy their power from unbundled generators often do so through long-term PPAs. To mitigate the risks to IPPs, these PPAs are often structured to ensure a minimum return to IPPs through mandatory payments that apply whether or not the utility uses the power produced (typically in the form of “capacity payments” that are based on installed capacity or “deemed energy” payments that are based on generation). In these cases, IPPs will require compensation for any additional risks resulting from higher capital intensity through higher contract values. Similarly, unbundled generators that sell their power to network utilities in wholesale markets will pass on any additional risks resulting from higher capital intensity through their short-term prices.

BOX 2

Higher utility capital intensity and vulnerability to shocks

Interest rate shocks: The hypothetical utility above is more vulnerable to interest shocks in a *with-transition* scenario. If interest rates increase, the utility's actual cost of capital increases immediately, but the regulated cost of capital that the utility is permitted to pass on to consumers, which is set by regulators based on historical averages, takes more time to adjust. Thus, the increase in interest rates causes the hypothetical utility's actual cost of capital to exceed its lagging regulated cost of capital. The negative impact of this interest rate shock on the utility's cost recovery is higher in the *with-transition* scenario, in which the utility has a higher share of capital costs (Table 2, row 1). Reducing the lag between actual and regulated tariffs would reduce the impact on the utility's cost recovery, but would make consumer tariffs more volatile.

Asset impairment shocks: The exclusion of certain assets from a utility's regulated asset base is a risk for utilities operating under so-called "rate-of-return regulation," under which a utility's allowed revenues are determined in part by the value of its assets. Regulators may exclude assets that no longer serve the core business of the utility or that no longer align with the government's policy goals. An asset impairment shock reduces the hypothetical utility's cost recovery, as its allowed revenues decrease but its costs remain unchanged. The effect on cost recovery is considerably more pronounced in the *with-transition* scenario, in which the utility is more asset-heavy (Table 2, row 2).

Demand shocks: A sudden drop in demand may result from an economic crisis or an extraordinary event such as a pandemic. In the *with-transition* scenario, the utility has a higher share of fixed costs in its cost structure and will not be able to reduce its costs in response to negative demand shocks as easily. A drop in demand will therefore cause the utility's cost recovery to deteriorate more in the *with-transition* scenario (Table 2, row 3).

Table 2: Impact of interest rate, asset impairment, and demand shocks on cost recovery for the hypothetical utility, without and with the energy transition

Shock	Short - term impact on cost recovery	
	Without transition	With transition
1. Interest rates rise by 3 percentage points over 4 years	Cost recovery reduced by 19.5 percent	Cost recovery reduced by 21.5 percent
2. 25 percent of assets are impaired over a 5-year period	Cost recovery reduced by 2.5 percent	Cost recovery reduced by 4.0 percent
3. 10 percent reduction in demand in one year	Cost recovery reduced by 5.0 percent	Cost recovery reduced by 7.5 percent

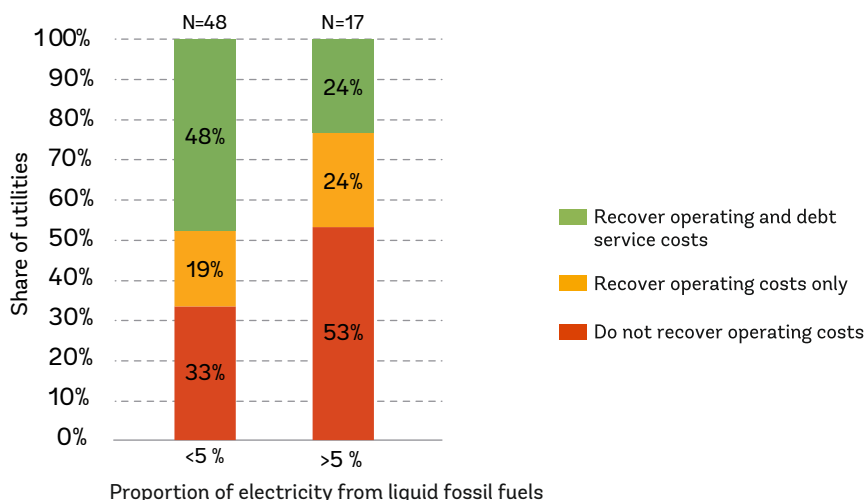


Decarbonizing the power supply can reduce utilities' exposure to liquid fossil fuel's cost volatility and create additional momentum for regional power trade.

Reducing their dependence on liquid fossil fuels presents a significant opportunity for utilities in LICs and MICs to lower their costs. In countries where poor planning or insufficient investment mean that utilities cannot keep up with growing demand, they often resort to generating power from liquid fossil fuels (such as diesel or heavy fuel oil [HFO]) as their primary or backup power source. This power is often obtained from the private sector on short-term contracts. These arrangements have the advantage that they are quick to install and contract and are fully dispatchable, but often come at significant cost to utilities. Figure 13 compares utility performance with the amount of power

produced at the country level from liquid fossil fuels. A share of liquid fossil fuel generation of over five percent of the total generation mix is associated with lower cost recovery. Importantly, high shares of generation from short-term liquid fuel sources often reflect the capture of energy sector decision-making by commercial interests more than they reflect sound technical and economic planning. Utilities can significantly lower their costs by reducing their dependence on liquid fuels and taking advantage of lower-cost renewable energy alternatives, especially when this is combined with appropriate system planning and procurement policies.

Figure 13: Utility cost recovery by proportion of liquid fuels in the national generation mix



BOX 3

HFO dependence and operating expense volatility in Western Africa

Many countries in Western Africa are heavily reliant on diesel and/or HFO for power generation, resulting in costs of supply that are more than double the average of those in OECD countries. For instance, until recently Sierra Leone and Liberia were almost entirely dependent on liquid fossil fuel generation during the dry season (December to May), while Chad’s entire N’Djamena power system is fueled by diesel and nearly half of Togo’s installed capacity uses HFO. In 2021, the region’s costs of electricity supply increased significantly when oil prices started to rise. In Sierra Leone, the average cost of HFO power from IPPs went up from historical values in the range of 16 to 18 cents per kWh to 22 cents per kWh in March 2022, and further to 27.4 cents per kWh in June 2022.

These rising costs have significantly impacted the viability of utilities in these countries. Unable to pass exorbitant power purchase costs on to consumers, utilities have had to defer paying their suppliers, resulting in load shedding and large arrears on utility balance sheets. Many utilities have also turned to governments for financial support. To reduce the region’s dependency on liquid fuels and exposure to associated price shocks, a new regional World Bank project is supporting the rapid installation and operation of approximately 106 megawatts (MW) of solar energy with battery storage, 41 MW of new hydroelectric capacity, and electricity distribution and transmission interventions to deliver this power to consumers.

Reducing their dependence on liquid fossil fuels can also help utilities reduce their exposure to fluctuations in international commodity prices. Many utilities in LICs and MICs suffer from significant volatility in the costs of their inputs, especially from volatility in the prices of oil and natural gas. This problem is especially pronounced for utilities that rely heavily on a single generation source for their energy needs and have little influence over the costs of their inputs. This is the case, for example, in power sectors where imported fossil fuels make up a large share of generation and are purchased predominantly in short-term markets. Unpredictable and often steep swings in costs create challenges for utilities, independently of absolute cost levels. Consumers value predictability in power pricing, and significant short-term rises in tariffs to accommodate fluctuating fuel costs can be politically challenging to implement, even if tariffs are low. Regulators and policymakers are therefore often reluctant to allow utilities to pass on volatile input costs to their customers. As a result, utilities may be left grappling with these cost fluctuations and see their financial sustainability further eroded. Volatility in operating costs makes it challenging for utilities to plan for long-term infrastructure investment, and uncertain and

unpredictable costs prevent utilities from effectively allocating resources. This can disrupt essential maintenance and expansion projects and reduce the reliability and resilience of the power grid. Also, utilities that have volatile operating costs are riskier prospects for investors, which makes it even harder for utilities to finance new projects at affordable terms. Box 3 illustrates how dependence on HFO has impacted some utilities in Western Africa.

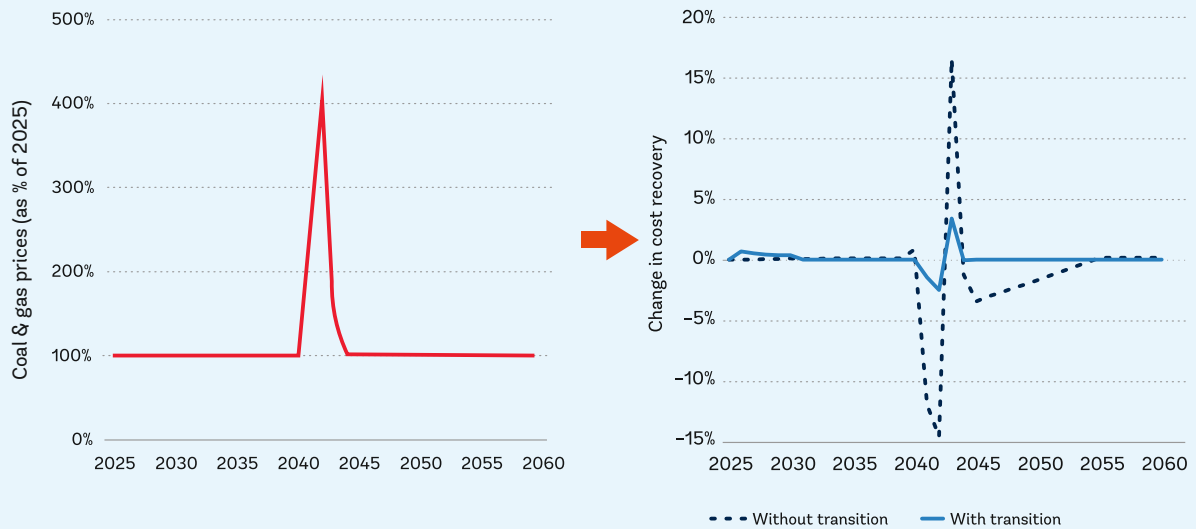
Having a larger share of renewable energy sources in a utility's generation mix can help reduce the impacts of commodity price volatility. First, diversifying generation can reduce the effect that fluctuations in the price of a particular fuel or power source can have on a utility's overall costs. Second, procuring renewables with competitive, long-term contracts provides utilities with a degree of price predictability over extended periods, which facilitates both country-level power sector planning and utility-level budgeting. Competitively priced renewable energy can therefore help mitigate the financial shocks associated with volatile operating costs. Box 4 shows the benefits of reducing fossil fuel dependence for a hypothetical utility.

BOX 4

The impact of a fossil fuel price shock on utility performance with and without the transition

The higher share of VRE under the energy transition makes the hypothetical utility analyzed above less vulnerable to fluctuations in fuel prices. The utility is assumed to purchase all of its fuels in short-term markets, either in the spot market or via short-term contracts. The fuel price shock affects the utility's actual fuel prices immediately, but the shock's impacts on regulated costs are delayed as there is a lag in the regulator's reaction to cost fluctuations. In the with-transition scenario, which has a higher share of VRE, the utility experiences less severe swings in cost recovery as a result of the price shock (Figure 14).

Figure 14: Impact of a fossil fuel price shock on utility cost recovery, with and without the energy transition



Decarbonizing generation also offers a significant opportunity for utilities and countries to realize greater gains from interconnection and cross-border power trade. Commitments to achieving the energy transition can provide the necessary impetus to accelerate the physical and regulatory integration of power systems, which is necessary for power trade to function effectively. Increased trade between countries or power systems offers utilities a number of potential benefits. By drawing on a greater range of generation sources spread across a broader geographic area, trade can make power supply more secure, make it easier to

manage the variability of renewable energy sources, further diversify generation sources, and balance networks by channeling excess energy to other countries with higher demand. This, in turn, can reduce the need for costly local solutions to manage variability. As a result, power trade can improve reliability and service quality, lower both the magnitude and variability of utilities' operating costs, and reduce the need for capital expenditures across the trading region. For many utilities, integrating power sectors and boosting power trade could provide the most cost-effective way to meet decarbonization targets while also maintaining a secure power supply.



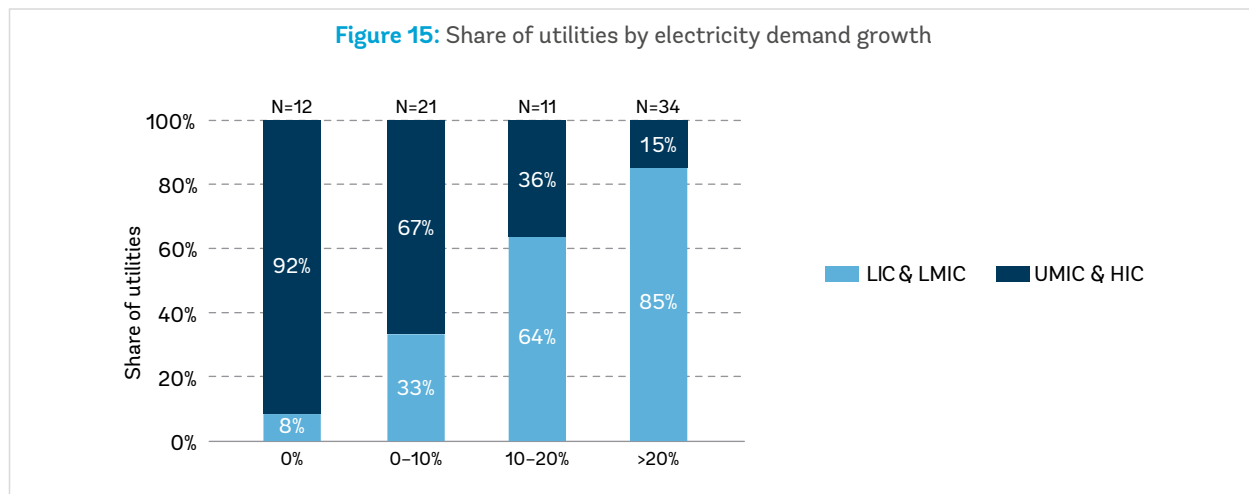
Demand for electricity will grow but may become increasingly supplied by DERs.

The drive to universal access to electricity in LICs and electrification of transport and industry in some LICs and MICs could result in rapid rises in demand for many utilities. On the one hand, this means that utilities would have a higher demand base

across which to spread their fixed costs, which might therefore be easier to recover. On the other hand, rapid growth could also create new administrative and financial challenges as utilities will need to upgrade and expand their management systems and capabilities to accommodate a higher level of activity.

This includes keeping up with growing workforce requirements via new hiring and training or managing a larger number of suppliers and lenders. As shown in Figure 15,

utilities experiencing the highest growth in demand are predominantly in LICs and LMICs, which already struggle disproportionately with cost recovery.



Rapid increases in power sales could also increase working capital needs or the costs of interest during construction, which utilities are not always permitted to pass on to consumers. Around 65 percent of the utilities analyzed in Section 2 of this paper reported having receivables days that exceeded their payables days—that is, they take more time on average to collect payments from their customers than they have time to pay their suppliers. For these utilities, demand growth under the transition will increase this working capital gap. To incentivize efficient collections and payment practices, some regulatory regimes do not allow utilities to finance working capital from tariffs. Similarly, to incentivize utilities to avoid delays or cost overruns, regulators may restrict them from including interest costs that are related to the financing of an asset that is still under construction (“interest during construction”). Rapid demand growth under the transition may increase the amount of financing that utilities require to meet these

additional needs and cause additional cost pressure if these are not provisioned for in retail tariffs.

Even as overall electricity demand increases, the energy transition will also bring new alternatives to grid power that could diminish interest in utilities’ traditional grid services. DERs such as household rooftop solar will offer increasingly attractive alternatives to the grid for some utility customers. This could be the case, for instance, if governments offer financial incentives to promote DER adoption or in systems where power service is unreliable. Under traditional volumetric tariff approaches, where customers pay only for the amount of power they consume, decreased grid electricity consumption due to higher penetration of DERs means that a utility’s past and future fixed costs (including from investments to support the energy transition) will have to be spread over a smaller demand base.

To compensate, utilities may need to raise tariffs and thus further increase customers' incentives to shift from grid power to DERs. This utility "death spiral" will be especially pernicious under progressive block tariff structures, in which customers' tariffs increase proportionally to the amount of power they consume. Under these structures,

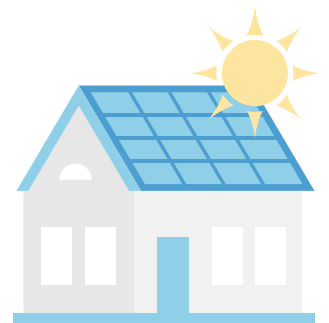
the customers who consume the most power have the strongest incentive to reduce their grid power consumption. In many systems, these customers account for a disproportionate share of utility revenues, and utilities can least afford to lose them. Box 5 illustrates some of these challenges in Jordan.

BOX 5

DERs and utility performance challenges in Jordan

By the end of 2022, self-generation from household solar amounted to more than one thousand MW of installed capacity in Jordan, or 42 percent of total renewable generation capacity in the country. This resulted in a noticeable reduction in the demand for grid power during the day (when rooftop solar systems were generating), followed by a sharp increase around sunset (when solar systems stopped generating). Jordan's net metering policy allowed self-generators to sell their excess electricity to the grid at retail prices and deduct this from their power bills. This created financial challenges for NEPCO, Jordan's single off-taker and bulk power supply utility, because the net metering policy did not recognize differences in the marginal costs of power between when it was abundant (during the day) and when it was scarce (during the evening peak), and this overcompensated self-generators for the power they injected into the grid.

To address this problem, the Jordanian regulator recently issued regulations requiring self-generating consumers (with very few exceptions) to pay monthly network usage fees that are proportional to the amount of self-generating capacity they have connected to the grid (two Jordanian Dinars per kW of installed self-generating capacity). As a next step, the regulator plans to switch from the current net metering policy to a net billing policy that sets prices closer to marginal costs. This will ensure a more balanced treatment as self-generators will contribute to the costs of enabling them to provide electricity to the network.





New business models and digital tools create opportunities for network utilities to better manage grids and expand their service offering to customers.

The transition will introduce new tools for managing demand and supply and improving service reliability. New digital tools, technologies, and business models will allow consumers to deliver electricity produced by their DERs to other consumers, or to store it for later use, for instance in batteries or electric vehicles. These systems could store excess energy from renewable sources, which could then be discharged during peak times to fulfill demand. Industrial customers could adjust their energy usage in response to power system constraints (“demand response”). This would allow utilities to even out temporary peaks and valleys in daily demand instead of varying supply by turning power stations’ generators up and down. Residential customers could participate in utility-funded energy efficiency programs that install energy-efficient lighting, programmable thermostats, and equipment such as smart power strips,¹⁸ and, in turn, help utilities to achieve their annual energy savings targets. These rapidly spreading innovations could help to make sure that networks are run more efficiently; ensure the smooth coupling of the electricity, e-mobility, and heating sectors; reduce the costs of asset maintenance and equipment failures; optimize the operation of grid-connected generation; defer distribution and transmission capacity investments; and mitigate grid congestion and technical and commercial losses.

Utilities can draw on new business models to expand their service offerings and their value propositions to consumers. On their own, or through third parties, utilities could offer services to customers in their service area who would be willing, for example, to deploy distributed solar on their premises. Utilities’ services could then comprise the design, financing, installation, operation, and maintenance of these DERs. Utilities could also leverage their technical competence by providing associated project management services to customers, including specifying equipment standards, developing and vetting project design, and standardizing contracts for DERs. In addition, utilities could improve their customers’ access to DERs by providing low-cost financing or including repayments for DER equipment financing in customers’ power bills (Box 6 illustrates how utilities in India were able to take advantage of some of these new business lines). This approach could be particularly beneficial in countries that suffer from damaged infrastructure and unreliable power supply due to fragility, conflict, and violence. In these countries, utilities could use DERs to provide stable and independent power sources directly to consumers, which would avoid the vulnerabilities of a central grid. This strategy could help to build utilities’ resilience, as well as strengthen relationships with their customers.

18 - Smart power strips are designed to reduce the amount of energy used by consumer electronic devices by shutting off the supply of power to devices that are not in use.

BOX 6

Enhanced utility service offerings for DERs and peer-to-peer electricity trading in India

Tata Power, India's largest power company, provides electricity distribution services in North and North West Delhi. The company allows customers to use electricity generated from rooftop solar systems to offset their power bills, with two additional features. First, Tata Power offers several different financing arrangements in conjunction with local banks to help customers purchase rooftop solar systems, while also offering maintenance services for installed systems. Second, all customers are charged a two-part retail tariff, with fixed charges based on capacity and variable charges based on the energy they consume. This model means that Tata Power can manage the revenue risk from DERs through the two-part tariff while also benefiting from additional revenue streams from the sale and maintenance of solar systems.

This arrangement was expanded in 2021 when Tata Power and the Australian technology company Power Ledger, in collaboration with the India Smart Grid Forum, introduced a trial of a peer-to-peer energy trading system based on blockchain technology, which enabled the direct trade of over 2 MW of solar PV among customers in North Delhi. Customers could choose whom to buy their electricity from, and the blockchain audit trail of energy transactions provided quick settlement and full transparency. These kinds of trading platforms provide a market-based alternative to dealing with surplus energy under net metering and net billing arrangements, while also creating incentives to install storage and provide other forms of flexibility.

New tools and business models could also help to better target grid expansion efforts, reducing the financial burden to utilities from growing their networks. Historically, government universal access programs in LICs and MICs have often required utilities to pay for the capital costs of grid extension as well as cover any operating losses resulting from serving what are often remote, low-demand new customers. Some governments have committed to compensating utilities for these shortfalls, but this compensation is often insufficient or delayed. These challenges can

be mitigated by least-cost geospatial planning tools that are now available to help utilities and governments identify which connections are most economically served through power grid expansion and which are more effectively reached through off-grid technologies, such as mini-grids or solar home systems. New approaches to electrification, in which utilities partner with financiers and appliance distributors to stimulate the adoption of income-generating appliances (“productive use”) can also help improve the financial case for grid electrification. Box 7 describes some of these trends in Kenya.

BOX 7

Utility performance and the push toward universal access in Kenya

Kenya has undergone one of the most dramatic energy access expansions in recent history, having increased its electricity access rate from 25 percent in 2010 to 75 percent in 2019. A large share of this increase in access came from new connections to KPLC—Kenya’s power distribution and retail utility. Recognizing that the new connections would be in rural areas with predominantly low-volume household consumption, the Government of Kenya instituted a last-mile connection policy through which KPLC’s connection costs, and revenue shortfalls from servicing these connections, would be covered by public funds. In practice, the government’s fiscal constraints meant that compensation for last-mile connections was often delayed or did not materialize. However, KPLC continued to connect new last-mile customers. This has caused significant financial difficulties for KPLC as well as deteriorating service quality as KPLC has not been able to mobilize sufficient funding to accompany grid extensions with the investments needed to strengthen its network.

As Kenya embarks on its final push toward universal access, KPLC is drawing on more streamlined, cost-effective approaches to last-mile electrification that are based on new technologies, planning tools, and utility business models. These include geospatial electrification planning to identify whether new connections can be most economically achieved through grid extension or off-grid technologies such as solar home systems and mini-grids; using demand and network data to better target electrification on technical and economic grounds; and working directly with financiers and appliance distributors to mainstream the use of income-generating appliances and stimulate electricity demand in newly electrified areas.





Section 4

Empowering Utilities for the Energy Transition and Universal Access

Utilities cannot navigate the shifting power sector landscape alone.



Utilities cannot navigate the shifting power sector landscape alone. The challenges and opportunities discussed in the previous section will impact utilities in different ways, depending on each utility's technological, political, and economic context, as well as its capacity and capabilities. For some utilities, the goals of the energy transition and universal access already closely align with their corporate and financial objectives. For other utilities, meeting these objectives may

require a major departure from their standard operations, with significant financial downsides. In all cases, concerted action will be required from policymakers, regulators, financiers, and utilities themselves to ensure that: i) utilities are prepared to manage a rapidly evolving power sector; ii) policy-level and utility-level incentives are properly aligned; and iii) additional costs to utilities and their consumers arising from decarbonization and universal access are managed and appropriately compensated.

-----> The role of governments

Governments can reduce the costs of the transition to utilities by reducing private sector risk. While the costs of energy access expansion and transition will in part be determined by exogenous factors such as the price of solar panels and other materials, a considerable share of the costs will depend on energy investors' perception of sector-level risks. By providing stable, predictable, and transparent laws and policies, governments can help to reduce the risk premiums that investors require and, thus, the costs for utilities and consumers of private capital. This includes developing transparent frameworks for public-private partnerships (PPPs) and creating clear rules concerning permitting, grid access, and power dispatch. In areas where the siting and permitting of transmission and distribution lines require action by many different authorities that govern access to public or private lands, governments need to ensure good coordination and efficiency by setting clear expectations and predictable timelines and processes.

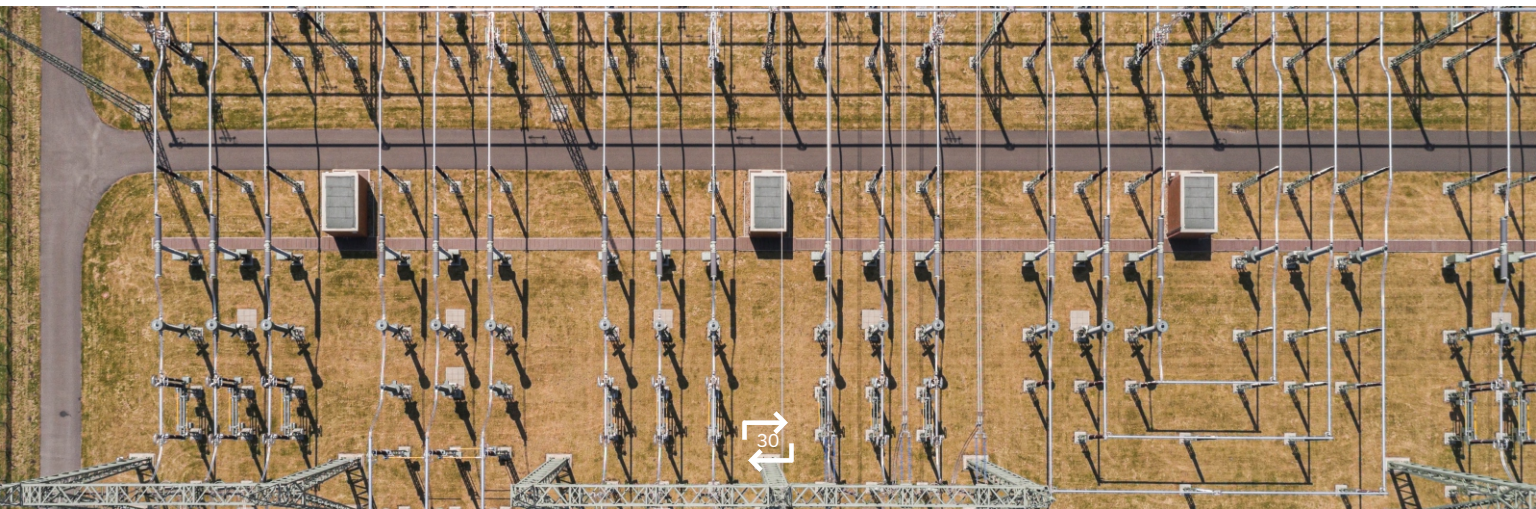
Similarly, a procurement framework based on fair and transparent bidding and selection can help drive down costs compared to negotiated contracts or feed-in-tariff policies. Where markets are not yet sufficiently mature for open competition, non-competitive procurement should still be based on rigorous and transparent technical and commercial criteria. Reducing sector risk through sound policymaking and robust procurement practices are among the most effective tools that governments have to minimize the costs of the transition. This will be especially critical for utilities that have heavily relied on concessional financing in the past, and whose financing costs will rise as they mobilize greater amounts of private capital.

When setting transition targets and formulating power sector plans, governments should consider all related costs and their impact on utilities. Policymakers should consider the full impact that policies will impose on utilities and make sure that utilities are not burdened with excessive or hidden costs. Regarding decarbonization, renewable energy targets should take the full costs of achieving them into consideration, including the costs for transmission and distribution grid investments that are required to integrate new renewable generation.

The role of governments

Planners must also ensure that policies that incentivize the rapid development of new renewable energy projects include careful monitoring of overall system needs and that they avoid committing to increases in generation capacity beyond what utilities and consumers can absorb. Regarding efforts to increase access to electricity, least-cost access expansion planning can ensure that the grid is only extended to areas where it is economically efficient to do so when compared to off-grid alternatives. Where grid extension is least-cost, or other options are not available or politically desirable, governments need to ensure that the commercial performance of utilities does not suffer as a result of implementing socially motivated connection expansion campaigns. This could entail, for example, providing utilities with adequate compensation for serving low-consuming customers in remote areas, and keeping loans used to finance non-commercial access investments off utilities' books. In addition, promoting policies and incentives focused on demand management and energy efficiency could help mitigate the challenges of rapidly growing demand and reduce the impact of decreasing subsidies on consumers.

Governments should remove subsidies that do not support the goals of the transition or universal access, and ensure that their own obligations to utilities are paid. Creating a level playing field for renewables will require governments to remove distorting fossil fuel subsidies, but to do so in a way that is sustainable for both utilities and consumers. In many LICs and MICs, subsidies for fossil fuels make fossil fuel power artificially attractive. This creates strong disincentives for utilities to increase the share of renewables in their generation mix and for consumers to accept the potentially higher prices of unsubsidized power. While phasing out these subsidies will be fundamental for a successful energy transition, this will require a concerted effort by utilities and policymakers to devise phase-out strategies that do not create overly abrupt changes in utilities' and consumers' costs. This could involve introducing compensatory incentives to make renewable energy adoption more appealing for utilities as subsidies are phased out. Also, some of the funding spent on fossil fuel subsidies could be reallocated to mitigate the financial impacts on utilities and consumers. Finally, since governments are often among the largest utility customers, they can further help utilities by paying their own electric bills on time.



-----> The role of regulators

Utilities need to be allowed to recover reasonable costs, including costs incurred as part of achieving their government’s energy transition or electricity access goals.

Sustainable financial performance of power utilities can only be achieved if the revenues they bill and collect are sufficient to cover their costs of operation. This requires that regulators be free to set tariffs based on clear, transparent methodologies without ad-hoc government interference. When governments keep tariffs low for certain customer groups for political or strategic reasons, cross-subsidies from other tariff categories or fiscal transfers need to make up for any shortfalls. Regulators also need to be able to monitor performance effectively and react to utilities’ tariff filings in a timely, transparent, and accountable manner.

Innovations in tariff setting may be required to manage new volatility in utilities’ costs.

Although the principles underpinning cost recovery will remain as important as ever to ensure utilities’ sustainability during the energy transition, the transition’s demands may create new pressures on cost recovery even for utilities that are currently well-regulated. As some utilities incur greater capital costs to finance transition-related infrastructure and experience rapid growth in demand, regulators may need to explore options for dynamic tariff-setting mechanisms that are more responsive to external shocks. This could include more frequent tariff reviews or the provision of additional “pass-throughs” for transition-related costs that cannot be reasonably controlled by the utility (for example, costs arising from interest rate shocks, which may be amplified for utilities that have borrowed to undertake large infrastructure expansion programs). Regulators that do not already allow utilities to include working capital, interest during construction, and other financial costs in their revenue requirements may need to consider accommodating these. Of course, preserving utility cost recovery under the transition will need to be balanced with keeping tariffs predictable and affordable for consumers to reduce the risk of political backlash. This will require greater transparency from regulators and utilities in determining and communicating the allocation of costs between utilities and their customers.

New tariff-setting approaches will be required to deal with the impacts of distributed energy resources.

Most of the challenges linked to higher penetration of DERs among utility customers are pricing-related and will require appropriate regulatory responses to manage. Regulators will need to ensure that the grid customers who adopt DERs continue to pay their fair share of the network and generation capacity costs that are required to ensure their continued connection to the grid. The use of two-part tariffs with both a component based on ongoing consumption and a component based on maximum demand can help address this. The prices paid to DERs for supplying energy to the network should reflect as closely as possible the value to the power system of that energy at that time. Time-of-use tariffs, which are particularly useful when there are large differences in the costs of service delivery between peak and off-peak hours, are one way of helping to achieve this.

The role of regulators

Regulations will need to be adapted to help utilities manage upcoming changes to the nature of supply and demand. Traditional approaches to balancing supply with demand by ramping up or reducing dispatchable sources of generation will become less effective in systems that have large additions of renewable generation. New grid technologies, however, offer new sources of flexibility by targeting both supply and demand. Policies and regulations should, therefore, provide incentives for utilities to invest in innovative infrastructure and digital tools that can better leverage supply and demand data to improve system flexibility. This includes smart meters and smart grids, cogeneration, demand response, energy efficiency, and electricity storage, as well as incentives to extend the useful life of assets to avoid unnecessary investments. Often this will require removing outdated legislation or technical regulatory requirements, such as those that preclude peer-to-peer trading of electricity among DER providers or that arbitrarily exclude the participation of unconventional resources such as battery storage. Encouraging additional energy solutions to enter power systems and augmenting the available power supply requires strong regulatory frameworks that provide metering data standards, proper wheeling tariff design, and ensure that utilities, DER resource aggregators, and mini-grids all face the same set of responsibilities for maintaining the grid's flexibility. Box 8 discusses regulatory innovation in Great Britain.



BOX 8

OFGEM RIIO (Revenue = Incentives + Innovation + Outputs) in Great Britain

To encourage efficient investment, the RIIO framework of OFGEM (Great Britain’s electricity market regulator) rewards the three British companies that it regulates for innovations to better meet the needs of their network users and consumers. To make sure that investments provide value for customers, and that network companies deliver on the performance targets and commitments outlined in their business plans, OFGEM sets cost and quality incentives that are based on reviewing exactly how much each company can spend, and on what. If OFGEM determines that a proposal is closer to efficient costs, the company will receive a higher incentive. Thus, if a company spends less than the amount allowed by OFGEM, it can retain a portion of what it saves (the incentive).

This motivates utilities to invest in innovation and customer service. In addition, OFGEM’s regulations focus on TOTEX (total expenditures) so that utilities are financially incentivized to reduce their total costs by making tradeoffs between their operating costs and capital costs. The RIIO framework, which was introduced in 2015, has been credited with enabling British utilities to reduce their carbon footprint by over 49 percent. The RIIO framework has also helped to improve the reliability of utility grids, as the number of power cuts has fallen by a fifth, and the average length of interruptions has fallen by 15 percent.

-----> The role of utilities

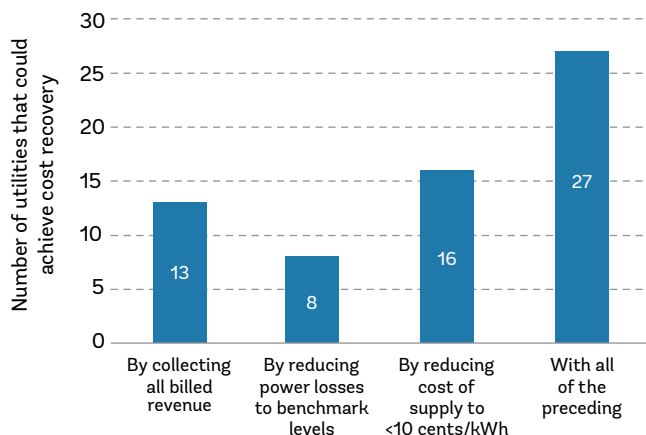
While good policies and regulations create the foundation for a sustainable energy transition, utilities must also play their part. Even in countries that have adopted sound policy and regulatory principles, it will ultimately be up to utilities to determine to what extent they are able to turn a favorable operating environment into long-term financial sustainability. Utilities’ responsibilities include keeping the costs that are under their control—such as administrative costs and, to some extent, financing costs—to reasonable levels. Poor operational and financial performance makes utilities a riskier target for private investment, raising utilities’ costs of capital or deterring some private investment altogether. Twenty-seven utilities included in the UPBEAT database could achieve cost recovery by improving their collections and reducing their system losses and costs of supply to below benchmark levels¹⁹ (Figure 16). This would require utilities to implement efficient investment plans and programs to sustainably reduce technical and commercial losses, as well as revenue protection plans to improve customer billing and payment collection.

19 - Benchmark losses here are 2 percent for transmission losses and 10 percent for distribution losses; benchmark costs of supply here are 10 cents per kWh, which is roughly the median for utilities in HICs.

The role of utilities

Better use of management information systems can help utilities manage and reduce interruptions; maintain voltage levels; record, bill and collect payments for electricity consumption; and manage corporate resources. Utility performance targets can be codified in concession agreements (for private utilities), in performance contracts, or as conditions for government guarantees for new utility financing.

Figure 16: Number of utilities that could achieve cost recovery by addressing key performance challenges



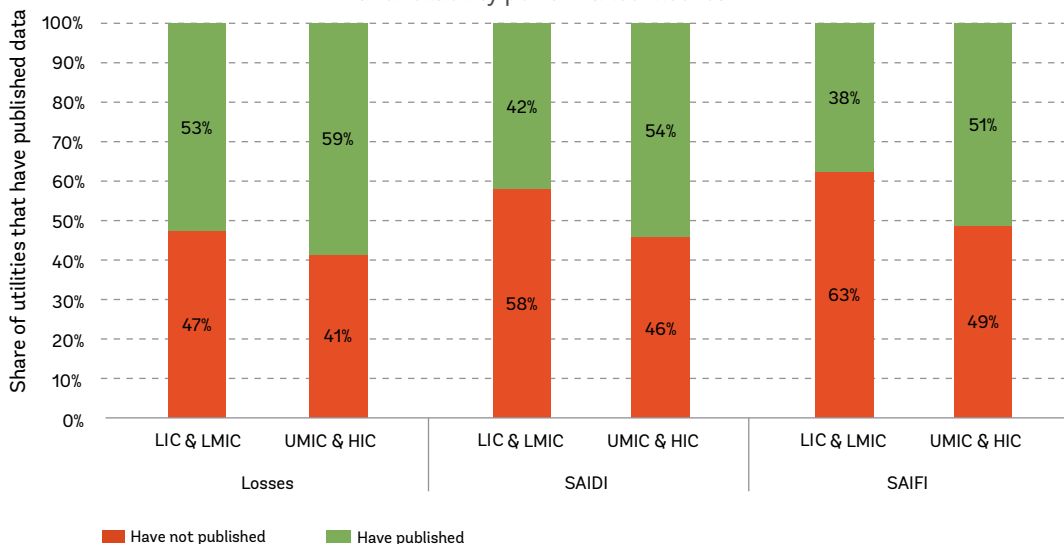
Outdated management and governance practices contribute to poor utility commercial and operational performance just as weak infrastructure and regulations do.

For utilities in LICs and MICs to thrive under the energy transition, they must not only be effective transporters of electricity, but also competently managed, and have the technical skills and organizational agility to seize new commercial opportunities, and mitigate new risks. Utilities' technical departments will need to become experts on how changing supply and demand patterns will impact power network management and how to use a growing universe of IT systems for grid and customer management. Finance departments will need to develop the capabilities to source and manage capital that aligns with the long-term investments necessary for supporting the transition, as well as know how to tap into new international and domestic sources of climate and sustainability-linked finance. Procurement and planning departments need to prepare for the grid upgrades necessary for DERs, VRE integration, and improved resilience and energy security. All of this needs to be facilitated by a management approach that hires, compensates, and rewards employees based on performance, overseen by strong government-led transparency and accountability measures.

The role of utilities

As the link not just between supply and demand but also between capital and consumers, utilities need to be able to communicate credibly with both their financiers and their customers. Of the 182 utilities analyzed here, 23 had no financial data available for the years after 2019. Only about half of utilities in the UPBEAT database make metrics for power losses publicly available, and fewer than half, even in higher-income countries, report standard reliability indicators such as SAIDI²⁰ or SAIFI²¹ (Figure 17). Several utilities, particularly in LICs and LMICs, lack even the basic systems to measure operational indicators. Poor reporting standards may also extend to deficiencies in communicating tariff changes to utility customers, which can undermine public perception of their legitimacy. If utilities are to continue to have the confidence of both financiers and customers as they navigate the complexities of the energy transition, then transparency, accountability, and effective communication must be among their top priorities.

Figure 17: Share of utilities reporting basic efficiency and reliability performance metrics



The role of development finance and concessional capital

Utilities will have little incentive to make the investments, manage the assets, and develop the business models needed for the transition's success if they are left worse off financially as a result. The objectives of the transition are economic, social, and environmental in nature: governments and the global community have recognized the importance of providing universal access to electricity and mitigating climate change, and have set policy targets accordingly. The objectives of a utility are to deliver power to consumers, reliably and efficiently, while earning a reasonable return on investment.

20 - System Average Interruption Duration Index – the average outage duration for each customer.

21 - System Average Interruption Frequency Index – the average number of outages a customer experiences over a certain period.

The role of development finance and concessional capital

There are no inherent reasons for these objectives to perfectly align, and utilities would not necessarily pursue the aims of the transition and universal access for commercial reasons. Decarbonization targets may require additions of renewable energy capacity that exceed what utilities would consider to be financially optimal. The additional network infrastructure needed to absorb and transmit variable generation will also add significant costs. This will be true as well for publicly driven energy access programs if governments require utilities to finance grid expansions to remote, low-consuming customers, or if governments promote the adoption of DERs. While well-designed and well-enforced regulation can ensure that utilities are able to recover their reasonably incurred incremental costs by passing these on to consumers, there is a limit to the speed and magnitude of the tariff increases that customers can bear.

Private capital has an important role to play in energy transition financing, but the additional costs of the transition will be felt by utilities regardless of how they are funded. Given the scarcity of public funding, private sector investment will be critical in mobilizing the financing needed for the generation, transmission, and distribution infrastructure required to carry out the energy transition. This could either be in the form of PPPs where utilities pay private developers for electricity services or in the form of utilities raising debt and equity directly from private investors. Both approaches will require financially viable utilities to act as credible off-takers and borrowers. However, from the utility's perspective, while signing contracts with private investors for the supply of power or network services can help spread costs over time, contracts with private investors that support transition-related goals will often still represent additional costs. In addition, as private capital is typically more expensive than public or development capital, raising new private financing for the transition may also increase utilities' cost of capital.

Development finance and international concessional finance can therefore play a critical role in helping utilities and consumers in LICs and MICs manage the additional costs of the transition. Given the limited ability of many utility customers to pay for electricity, government budget constraints, and the global benefits of decarbonization, there is a strong case for providing utilities with international concessional financing to reduce the burden of the energy transition's incremental costs. Sufficient amounts of concessional capital could, theoretically, leave utilities and their customers no worse off financially when utilities make the investments needed for the transition. For example, the hypothetical utility modeled in Section 3 would require a 1.2 percentage point reduction in its cost of capital to offset the incremental costs of decarbonization. Box 9 explains this approach to estimating concessionality in more detail.

The role of development finance and concessional capital

Concessional capital could come in many forms, and not just as reductions in loan pricing.

Many utilities in LICs and MICs lack access to long-term debt and are unable to reliably refinance short-term debt. Longer tenors can help reduce utilities' annual debt service costs and better align the maturity of utilities' debt with the long lifetimes of network assets. Concessional capital can also fund risk-sharing mechanisms, such as guarantees, that make utilities less risky counterparties for IPPs and private lenders. Utilities in LICs and MICs are often highly vulnerable to exchange rate fluctuations as large shares of their power, capital, and other input costs are denominated in hard currency. For these utilities, risk-sharing mechanisms that mobilize local-currency private capital could be especially impactful. Concessional capital for utilities could also come from global carbon markets. These could provide utilities with grant-like capital that can be blended to improve the terms of other sources of finance, without imposing additional debt burdens. Whatever form concessional capital takes, development financiers need to make sure that it is accompanied by appropriate conditions so that it does not disincentivize policymakers and utilities from making the reforms necessary to further reduce the costs of the transition.

BOX 9

How much concessional capital? And at what price?

Decarbonizing power systems will require utilities to add VRE generation to their supply mixes and expand and modernize their power grids. For many utilities, these investments—whether they are financed from utilities' balance sheets or through contracts with the private sector—will impose additional costs that would not have been incurred without decarbonization targets. In many LICs and MICs, these additional costs stand in contrast to comparatively small contributions to global greenhouse gas emissions. Therefore, there is an argument for international concessional debt to help offset these incremental costs to utilities. One approach to estimating the required concessional debt is finding the reduction in a utility's cost of capital that would offset the additional costs of decarbonization. For the hypothetical utility examined in Section 3, a 1.2 percentage point decrease in its weighted average cost of capital (WACC) would equalize the present values of its regulated revenues with and without decarbonization. Reducing the utility's WACC in this way could be achieved by increasing the share of concessional debt in its capital structure and/or increasing the discount offered on concessional debt, compared to its commercial debt.

The role of development finance and concessional capital

Development finance also has an important role to play in strengthening the capacity of utilities, regulators, and other power sector institutions. This support can include strategies for integrating renewable energy sources into existing grids, balancing investments in distributed and grid-scale renewables, and establishing fair and transparent support mechanisms for new renewable energy. Also, dedicated capacity building will be required to help utilities manage increasingly complex network infrastructure. Development finance institutions can guide utilities and regulators in adapting to new market realities. This includes supporting the design of tariff systems that accommodate new technologies and consumer behaviors, and addressing the challenges of DERs and their impact on utility pricing structures. Finally, development financiers can play a crucial role as “honest brokers” between governments, domestic and international financiers, regulators, and utilities, and help to resolve differences between power sector actors that may not always share the same goals or incentives.



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