Chapter 8

Power: Catching Up

Africa's chronic power problems have escalated in recent years into a crisis affecting 30 countries, taking a heavy toll on economic growth and productivity. The region has inadequate generation capacity, limited electrification, low power consumption, unreliable services, and high costs. It also faces a power sector financing gap of approximately $23 billion a year. It spends only about one-quarter of what it needs to spend on power, much of which is on operating expenditures to run the continent's high-cost power systems, thus leaving little for the huge investments needed to provide a long-term solution.

Further development of the regional power trade would allow Africa to harness larger-scale, more cost-effective energy sources, thereby reducing energy system costs by $2 billion a year and saving 70 million tons of carbon emissions annually. Economic returns to investments in cross-border transmission are particularly high, but reaping the promise of regional trade depends on a handful of major exporting countries' raising the large volumes of finance needed to develop generation capacity for export. It would also require political will in a large number of importing countries that could potentially meet more than half their power demand through trade.

The operational inefficiencies of power utilities cost $3.3 billion a year, deterring investments in electrification and new capacity, while underpricing of power translates into losses of at least $2.2 billion a year. Full cost-recovery tariffs would already be affordable in countries with efficient large-scale hydropower- or coal-based systems, but not in those relying on small-scale oil-based plants. If regional power trade comes into play, generation costs will fall, and full cost-recovery tariffs could be affordable in much of Africa.

The key policy challenges are to strengthen sector planning capabilities, too often overlooked in today's hybrid markets. A serious recommitment to reforming state-owned enterprises (SOEs) should emphasize improvements in corporate governance more than purely technical fixes. Improving cost recovery is essential for sustaining investments in electrification and regional power generation projects. Closing the huge financing gap will require improving the creditworthiness of utilities and sustaining the recent upswing in external finance to the sector.

Africa's Chronic Power Problems

Africa's generation capacity, stagnant since the 1980s, is woefully inadequate today. The entire installed generation capacity of the 48 Sub-Saharan countries is 68 gigawatts, no more than Spain's, and without South Africa, the total falls to 28 gigawatts (EIA 2006). As much as one-quarter of that capacity is unavailable because of aging plants and poor maintenance.

The growth in generation capacity has been barely half that in other developing regions. In 1980, Sub-Saharan Africa was at approximately the same level as South Asia in generation capacity per million people, but it has since fallen far behind. Sub-Saharan African countries lag even compared with others in the same income bracket (Yepes, Pierce, and Foster 2008).

Only about one-fifth of the Sub-Saharan population has access to electricity, compared with about one-half in South Asia and more than four-fifths in Latin America. Since 1990, East Asia, Latin America, and the Middle East have all added at least 20 percentage points to their electrification rates, but access rates in Sub-Saharan Africa are relatively stagnant, as population growth and household formation outstrip new connections.

At current trends, less than 40 percent of African countries will reach universal access to electricity by 2050 (Banerjee and others 2008). Overall, household access to electricity in urban areas is 71 percent, compared with only 12 percent in rural areas. Moreover, access rates in the upper half of the income distribution exceed 50 percent, whereas they are less than 20 percent in the bottom half. Given that rural areas account for about two-thirds of the population, extending access presents a major challenge. Only 15 percent of the rural population lives within 10 kilometers of a substation (or within 5 kilometers of the medium-voltage line) and could thus be added to the electricity grid at relatively low cost. As much as 41 percent of the rural population lives in areas considered isolated or remote from the grid[1] and is reachable in the medium term only by off-grid technologies such as solar photovoltaic panels, which typically cost \$0.50–\$0.75 per kilowatt-hour (ESMAP 2007).

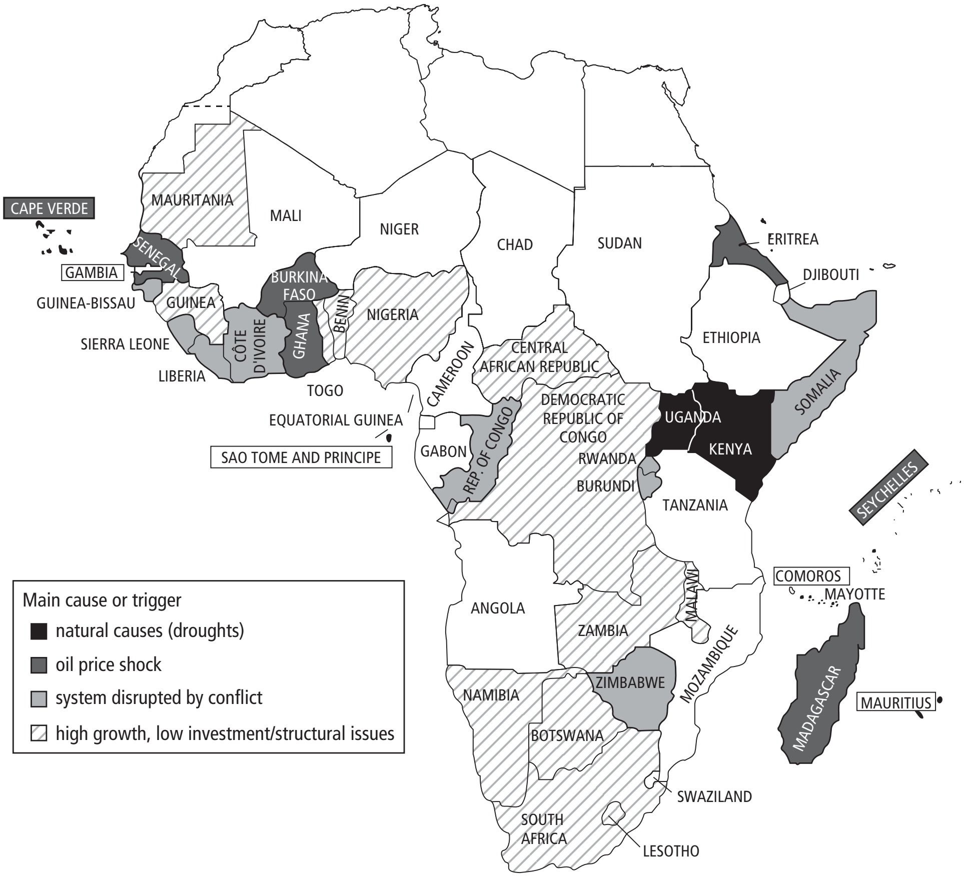
The cost of producing power in Africa is exceptionally high and rising. The small scale of most national power systems and the widespread reliance on expensive oil-based generation make the average total historic cost of producing power in Africa exceptionally high: \$0.18 per kilowatt-hour with an average effective tariff of \$0.14 per kilowatt-hour.[2] Compare that with tariffs of \$0.04 per kilowatt-hour in South Asia and \$0.07 in East Asia. Rising oil prices, lower availability of hydropower, and greater reliance on emergency leases have put further upward pressure on costs and prices.

Power consumption is tiny and falling. Given limited power generation and low access, per capita electricity consumption in Sub-Saharan Africa (excluding South Africa) averages only 124 kilowatt-hours a year, barely 1 percent of the consumption typical in high-income countries. Even if that power were entirely allocated to household lighting, it would hardly be enough to power one lightbulb per person for six hours a day. Sub-Saharan Africa is the only region in the world where per capita consumption is falling (World Bank 2005).

Power shortages have made service even less reliable. More than 30 African countries now experience power shortages and regular interruptions in service (figure 8.1). From 2001 to 2005, half of the countries in Sub-Saharan Africa achieved solid GDP growth rates in excess of 4.5 percent. Their demand for power grew at a similar pace, yet generation capacity expanded only 1.2 percent annually. South Africa shows what happens when generation capacity fails to keep up with demand (box 8.1). In some countries, supply shocks exacerbated the situation. Causes of the supply shocks include droughts in East Africa; oil price inflation, which made it difficult for many West African countries to afford diesel imports; and conflicts that destroyed the power infrastructure in some fragile states.

Inadequate power supplies take a heavy toll on the private sector. Many African enterprises experience frequent outages: in Senegal 25 days a year, in Tanzania 63 days, and in Burundi 144 days. Frequent power outages mean big losses in forgone sales and damaged equipment—6 percent of turnover on average for formal enterprises, and as much as 16 percent

Figure 8.1 Underlying Causes of Africa's Power Supply Crisis



Source: Eberhard and others 2008.

BOX 8.1

South Africa's Power Supply Crisis

South Africa has long had a reliable and cheap supply of electricity. However, delays in investment by the state-owned electricity provider Eskom (which provides 70 percent of the electricity in Sub-Saharan Africa), breakdowns of power plants, and negligence in coal contracting have eroded spare capacity in the system, leaving the country prone to periodic rounds of rolling power cuts. Many of South Africa's neighbors, dependent on imports, are also feeling the economic costs of power scarcities.

The government had earlier imposed a moratorium on Eskom's building new plants. It considered unbundling the utility and introducing private participation and competition in the market, similar to Nord Pool in Scandinavia or PJM in the United States. But the new market arrangements were never implemented, and with average prices far below the marginal cost of new generation, private investors had no way of entering the sector without special contracting arrangements. After a four-year hiatus, the government abandoned the idea of a competitive market and again charged Eskom with expanding capacity (while retaining the option of contracting with a few independent power producers in the future). These planning and investment failures are typical of hybrid electricity markets.

To help finance investment and reduce demand, electricity prices in South Africa will increase substantially over the next several years. But the supply-demand balance will likely remain tight for at least the next seven years, up to 2015, until new base-load generation capacity comes on line.

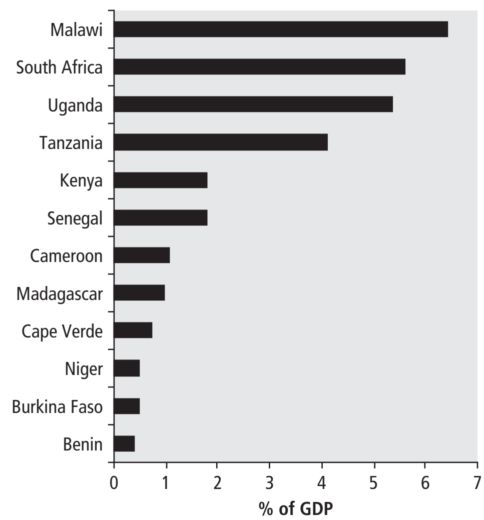
Source: Based on interviews with World Bank staff from the Africa Energy Department, 2008.

of turnover for informal enterprises unable to provide their own backstop generation (Foster and Steinbuks 2008). Therefore, many enterprises invest in backup generators. In many countries, backup generators represent a significant proportion of total installed power capacity: 50 percent in the Democratic Republic of Congo, Equatorial Guinea, and Mauritania, and 17 percent in West Africa as a whole. The cost of backup generation can easily run to $0.40 per kilowatt-hour or several times higher than the utility's costs of generating power (Foster and Steinbuks 2008).

The economic costs of power outages are substantial. The immediate economic cost of power shortages can be gauged by looking at the cost of running backup generators and forgoing production during power shortages. These costs typically range between 1 and 4 percent of GDP (figure 8.2). Over time, the lack of a reliable power supply is also a drag on economic growth. From the early 1990s to the early 2000s in Cameroon, Côte d'Ivoire, the Democratic Republic of Congo, Ghana, and Senegal, inadequate power infrastructure shaved at least one-quarter of a percentage point off annual per capita GDP growth rates (Calderón 2008).

A common response to the immediate crisis is to tender short-term leases for emergency power. Unlike traditional power generation projects, this capacity can be put in place in a few weeks, providing a rapid response to pressing shortages. Equipment is leased for up to two years, sometimes longer, and then reverts to the private provider. At least an estimated 750 megawatts of emergency generation is currently operating in Sub-Saharan Africa, representing for some countries a large proportion of their national installed capacity. Because of the preponderance of small diesel units, the costs have typically been $0.20–$0.30 per kilowatt-hour, and for some countries, the price tag can be 4 percent of GDP (table 8.1).

Figure 8.2 Economic Cost of Outages in Selected Countries



Source: Eberhard and others 2008, using World Bank 2007 data.
Note: Economic cost is estimated as the value of lost load multiplied by the volume of load shedding. Value of lost load is derived from country-specific estimates based on enterprise survey data for sales lost due to power outages.

Table 8.1 Economic Cost of Emergency Power Generation

Country	Emergency generation capacity (megawatts)	Total generation capacity (megawatts)	Emergency generation capacity (% of total)	Cost of emergency generation (% of GDP)
Angola	150	830	18.1	1.04
Gabon	14	414	3.4	0.45
Ghana	80	1,490	5.4	1.90
Kenya	100	1,211	8.3	1.45
Madagascar	50	140	35.7	2.79
Rwanda	15	31	48.4	1.84
Senegal	40	243	16.5	1.37
Sierra Leone	20	15	133.3	4.25
Tanzania	40	881	4.5	0.96
Uganda	100	240	41.7	3.29

Source: Eberhard and others 2008.

A Huge Investment Backlog

Addressing Africa's chronic power problems will require major investments in the refurbishment and expansion of power infrastructure. Of the 70.5 gigawatts of installed generation capacity, some 44.3 gigawatts need to be refurbished. An additional 7,000 megawatts of new generation capacity need to be built each year to meet suppressed demand, keep pace with projected economic growth, and provide additional capacity to support the rollout of electrification. Compare that with expansion of less than 1,000 megawatts a year over the period 1990–2005. The bulk of this new power generation capacity will be needed to meet nonresidential demands. In addition, raising electrification rates will require extending distribution networks to reach an additional 6 million households a year from 1996 to 2005.

The total spending needs of the power sector amount to $40.6 billion a year (Rosnes and Vennemo 2008), or 6.4 percent of the region's GDP, skewed toward capital expenditure (table 8.2). The greatest absolute spending requirements correspond to the middle-income countries, which need to spend $14.2 billion a year, but the largest economic burden is borne by the fragile states, which would have to devote an implausible 13.5 percent of GDP to meet this goal.

Economic growth is an important driver of demand for power generation capacity. The estimates of power investment needs presented earlier are based on growth projections before the onset of the 2008 global financial crisis. The International Monetary Fund reduced its GDP growth projections for Africa from 5.1 percent a year to 3.5 percent a year because of the global economic crisis. Sensitivity analysis suggests that even lowering the original projected growth rates of 5.1 percent to half their levels would reduce estimated power sector spending needs by only about 20 percent in absolute terms, lowering required new generation capacity from just over 7,000 megawatts to just under 6,000 megawatts. The decrease in required spending would be somewhat larger in the Southern and West African Power Pools and somewhat smaller in the Central and East African Power Pools. Even so, when power spending needs are expressed as a percentage of GDP, the effect of a slower-growth scenario is much smaller. Because slower growth reduces GDP as well as power spending needs, the overall economic burden of power sector spending needs is only very slightly lower under a low-growth scenario.

Existing spending on the power sector is $11.6 billion, or just over one-quarter of what is required. The adoption of high-cost generation solutions skews existing spending toward operating expenditure, leaving only $4.6 billion a year to fund the long-term investments to address the continent's power supply crisis, more than half of which comes from domestic public finance. Existing spending represents 1.8 percent of regional GDP, although

Table 8.2 Power Sector Spending Needs

	$ billions annually			Percentage of GDP		
Country type	Capital expenditure	Operation and maintenance	Total spending	Capital expenditure	Operation and maintenance	Total spending
Sub-Saharan Africa	26.60	14.00	40.60	4.20	2.20	6.40
Middle-income countries	6.29	7.90	14.19	2.30	2.92	5.22
Low-income fragile countries	4.50	0.70	5.20	11.70	1.80	13.50
Low-income nonfragile countries	7.60	2.20	9.70	6.90	2.00	8.80
Resource-rich countries	8.40	3.35	11.77	3.79	1.50	5.29

Source: Briceño-Garmendia, Smits, and Foster 2008.
Note: For a more detailed exposition of power sector spending needs, see chapter 2 in this volume. Totals may not add exactly because of rounding errors.

in the nonfragile low-income countries, this share increases to 2.9 percent of GDP. Of the external capital flows, finance from countries not belonging to the Organisation for Economic Co-operation and Development (OECD) is the most significant, accounting for $1.1 billion a year, primarily from the Export-Import Bank of China. Official development assistance follows at $0.7 billion a year and then private capital flows of $0.5 billion a year (table 8.3).

Most of the private sector finance recorded relates to independent power producers (IPPs). In recent years, 34 IPP contracts in Africa have involved investments of $2.4 billion for the construction of 3,000 megawatts of new power generation capacity. Those projects have provided much-needed generation capacity. An independent assessment concluded that they have also been relatively costly because of technology choices, procurement problems, and currency devaluations (calling for adjustments in dollar- or euro-denominated off-take agreements) (Gratwick and Eberhard 2008).

The existing resource envelope would go significantly further if the sector operated more efficiently. Addressing the operating inefficiencies of the power utilities could reduce the funding gap by $3.3 billion a year, improving cost recovery would bring an additional $2.2 billion a year, and $0.3 billion a year could be recouped by improving execution of the capital budget.

Even if all these inefficiencies could be eliminated, a sizable power sector financing gap of $23 billion a year would remain (table 8.4). Three-quarters of this financing gap is a shortfall in capital expenditure, while the remaining quarter is a shortfall in operation and maintenance spending. The largest portion of the gap—nearly $11 billion per year—corresponds to the middle-income countries. However, the largest financing burden relates to the low-income fragile states, where the financing gap amounts to roughly 7 percent of their GDP.

Table 8.3 Financing Flows to the Power Sector
$ billions annually

	Operation and maintenance	Capital spending					
Country type	Public sector	Public sector	ODA	Non-OECD financiers	PPI	Total	Total spending
Sub-Saharan Africa	7.00	2.40	0.70	1.10	0.50	4.60	11.60
Middle-income countries	2.66	0.80	0.03	0	0.01	0.80	3.50
Low-income fragile countries	0.60	0	0.04	0.20	0.01	0.30	0.80
Low-income nonfragile countries	2.00	0.40	0.60	0.10	0.20	1.30	3.20
Resource-rich countries	1.60	1.20	0.10	0.70	0.30	2.30	3.90

Source: Briceño-Garmendia, Smits, and Foster 2008.
Note: Operation and maintenance includes other current expenditures. ODA = official development assistance; OECD = Organisation for Economic Co-operation and Development; PPI = private participation in infrastructure. Totals may not add exactly because of rounding errors.

Table 8.4 Composition of Power Sector Funding Gap

	$ billions annually			Percentage of GDP		
Country type	Capital expenditure gap	Operation and maintenance gap	Total gap	Capital expenditure gap	Operation and maintenance gap	Total gap
Sub-Saharan Africa	17.6	5.6	23.2	2.7	0.9	3.6
Low-income fragile countries	2.6	0.1	2.8	6.9	0.2	7.1
Low-income nonfragile countries	4.5	0.1	4.7	4.1	0.1	4.2
Middle-income countries	5.5	5.2	10.7	2.0	1.9	3.9
Resource-rich countries	3.5	1.0	4.5	1.6	0.5	2.0

Sources: Briceño-Garmendia, Smits, and Foster 2008; Yepes, Pierce, and Foster 2008.
Note: Totals do not add because efficiency gains cannot be carried across country groups.

The Promise of Regional Power Trade

Although Sub-Saharan Africa is well endowed with both hydropower and thermal resources, only a small fraction of its power generation potential has been developed. Of the 48 Sub-Saharan countries, 21 have a generation capacity of less than 200 megawatts, well below the minimum efficiency scale, which means they pay a heavy penalty: costs reach \$0.25 per kilowatt-hour, twice the \$0.13 per kilowatt-hour in the region's larger power systems. One reason is that some of the region's most cost-effective energy resources are too distant from major centers of demand in countries too poor to raise the billions of dollars needed to develop them. For example, 61 percent of the region's hydropower potential is in just two countries: the Democratic Republic of Congo and Ethiopia.

Pooling energy resources through regional power trade promises to reduce power costs. The Southern, West, East, and Central African Power Pools, created mainly to support power trade efforts, are at varying stages of maturity. If pursued to their full economic potential, regional trade could reduce the annual costs of power system operation and development by \$2 billion per year (about 5 percent of total power system costs). These savings are already incorporated in the power sector spending needs previously presented. They come largely from substituting hydropower for thermal power, substantially reducing operating costs, even though it entails higher up-front investment in capital-intensive hydropower and associated cross-border transmission. The returns to cross-border transmission can be as high as 120 percent for the Southern African Power Pool and more typically 20–30 percent for the other power pools. By increasing the share of hydropower, regional trade would also save 70 million tons of carbon emissions a year.

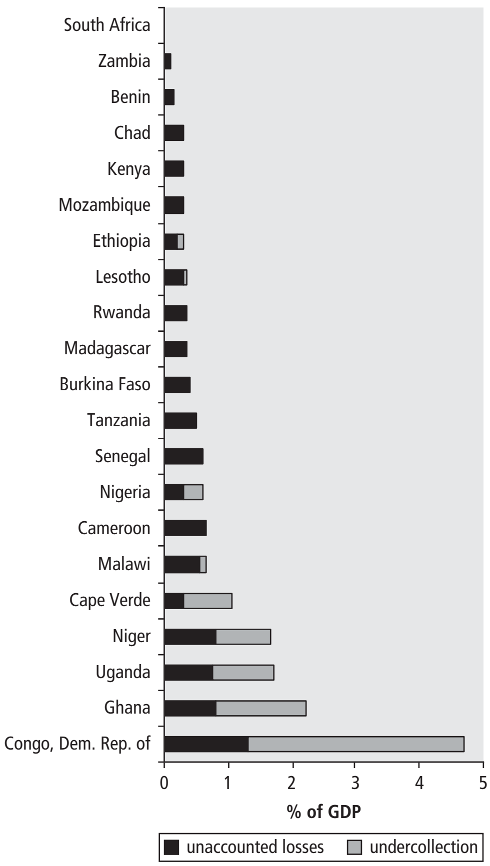
Under regional power trade, a handful of large exporting countries would serve a substantial number of power importers. The Democratic Republic of Congo, Ethiopia, and Guinea would emerge as the major hydropower exporters. As many as 16 countries would be better-off (from a purely economic standpoint), importing more than 50 percent of their power needs through regional trade. Savings range from \$0.01 to \$0.07 per kilowatt-hour. The largest beneficiaries tend to be smaller nations without domestic hydropower resources. For those countries, the cost of building cross-border transmission would be paid back in less than one year, once neighboring countries have developed adequate generation capacity to support trade. (For a more detailed analysis of regional power trade potential, see chapter 6 in this volume on regional integration.)

Improving Utility Performance through Institutional Reform

The operational inefficiencies of power utilities cost the region \$2.7 billion a year (0.8 percent of GDP on average; figure 8.3). They divide roughly evenly between distribution losses and revenue undercollections. Average distribution losses in Africa are 23.3 percent, more than twice the norm of 10 percent, affecting all countries to some degree. Average collection ratios are 88.4 percent, compared with the best practice of 100 percent. Burkina Faso, Ghana, Niger, and Uganda face much greater undercollections than the rest, up to 1 percent of GDP.

Operational inefficiencies have been holding back the pace of electrification and preventing utilities from balancing supply and demand. They drain the public purse and undermine the performance of the utilities. One casualty of insufficient revenue is maintenance. Utility managers must often choose among paying salaries, buying fuel, or purchasing spares. They must frequently cannibalize parts from other working equipment. The investment program is another major casualty. Utilities with below-average efficiency electrify only 0.8 percent of the population in their service area each year, much lower than the 1.4 percent electrified each year by utilities with above-average efficiency. Utilities with low efficiency also have greater difficulty in keeping pace with demand. The suppressed or unmet power demand in those countries exceeds 13 percent of total demand, twice the

Figure 8.3 Economic Burden Associated with Power Utility Inefficiencies in Selected Countries



Source: Briceño-Garmendia 2008.
Note: Power utility inefficiencies include undercollection of revenues and unaccounted-for distribution losses.

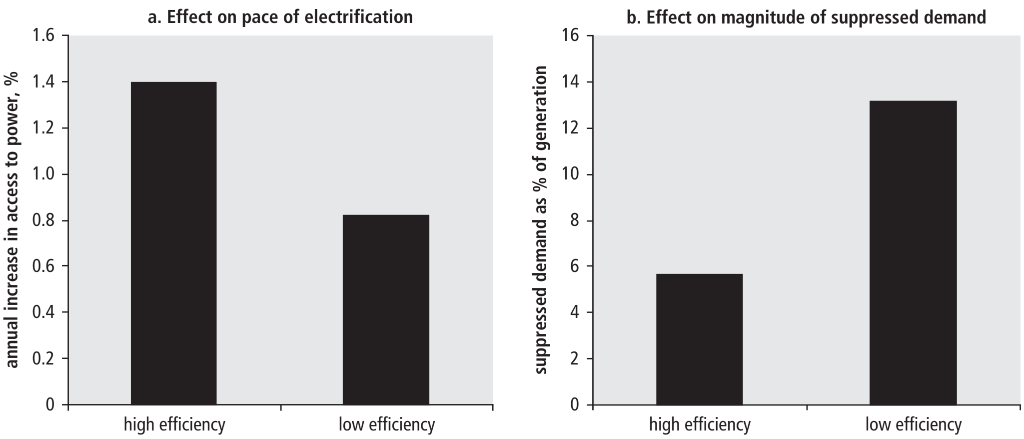
6 percent in countries with higher efficiency (figure 8.4).

Institutional reform measures hold the key to improving utility performance. Countries that have advanced the institutional reform agenda for the power sector show substantially lower hidden costs than those that have not, as do countries with more developed power regulatory frameworks and better governance of their state-owned utilities (figure 8.5). Measures that seem to have a substantial effect on reducing hidden costs are private participation in the power distribution sector and (among state-owned utilities) performance contracts that incorporate clear incentives. The case of Kenya Power and Lighting Company is particularly striking (box 8.2).

Labor redundancy is another source of utility inefficiencies. Power utilities in Africa have overemployment of 88 percent relative to a developing country benchmark of 413 connections per employee. Overemployment by utilities results in labor overspending in the range of 0.07 percent to 0.6 percent of GDP.

The application of management contracts has been more complex than originally supposed. More than 20 African countries have experimented with private sector participation in power distribution, split evenly between concessions and management contracts. Management contracts have attracted interest

Figure 8.4 Inefficiency in Utility Performance

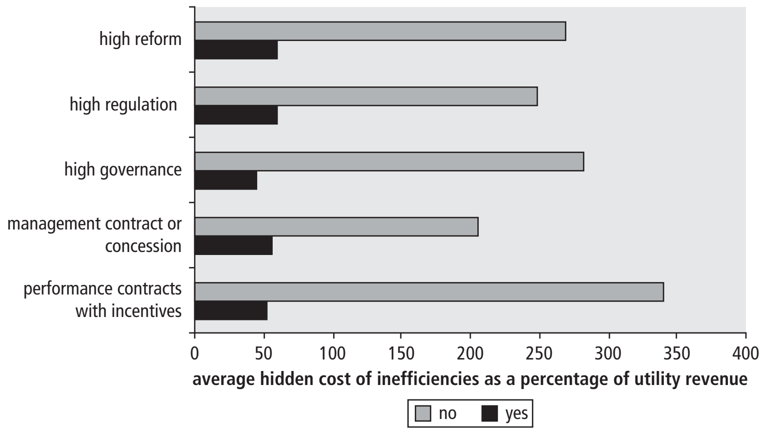


Source: Derived from Eberhard and others 2008.
Note: High efficiency refers to utilities with below-average levels of inefficiency caused by revenue undercollection and distribution losses. *Low efficiency* refers to utilities with above-average levels of inefficiency caused by revenue undercollection and distribution losses.

because they are a simpler way of addressing inefficiencies, but their application has proved complex and contentious, and they have not always proved sustainable. Of 17 African management contracts, 4 were canceled before the originally designated expiry date, and at least 5 more were not renewed after their initial term, reverting to state operation. Only 3 management contracts remain in place.

Problems with management contracts have included unrealistic expectations and limited ability to address broader sector challenges. First, many management contracts were undertaken with donor involvement. Donors saw the contracts as an initial step on the road to more extensive sector reform that would be extended

Figure 8.5 Effect of Reform Measures on Hidden Costs



Source: Briceño-Garmendia 2008.

BOX 8.2

Kenya's Success with Private Participation in Power

Kenya's Electric Power Act of 1997 introduced independent economic regulation, essential for private sector participation. It has since become government policy to put all bids for generation facilities out for competition, open to both public and private firms, and to give no preferential treatment to the national generator.

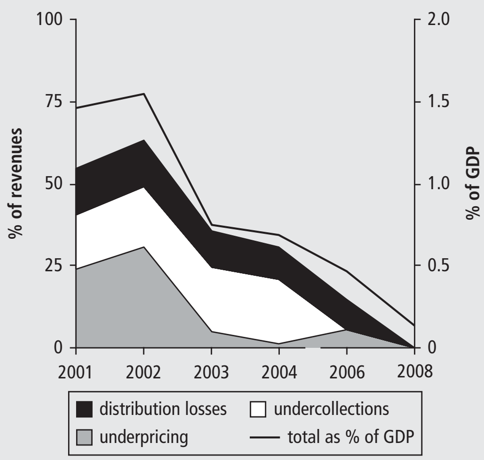
The sector was unbundled in 1998 when Kenya Electricity Generating Company (KenGen; generation) and Kenya Power and Lighting Company (KPLC; transmission and distribution) were established. KenGen is now 30 percent privately owned, and KPLC is 51 percent privately owned.

Established in 1998, the Electricity Regulatory Board (the Energy Regulatory Commission since 2007) maintains a significant degree of autonomy. It has issued a grid code and rules on complaints and disputes, supply rules, licenses, a safety code, and a tariff policy.

Four independent power producers supply about 12 percent of all power. Four more recently received licenses, and another three are expected to apply for licenses.

In the early 2000s, KPLC had substantial hidden costs in underpricing, collection losses, and distribution losses that absorbed 1.4 percent of GDP. In the run-up to a management contract, revenue collection improved from 81 percent in 2004 to 100 percent in 2006. Distribution losses also began to fall, though more gradually, reflecting the greater difficulty in resolving them. Power pricing reforms also allowed tariffs to rise in line with escalating costs, from $0.07 in 2000 to $0.15 in 2006 and to $0.20 in 2008. As a result of those measures, the hidden costs of the power sector fell to 0.4 percent of GDP in 2006 and were eliminated by 2008 (see figure). This outcome put the sector on a firmer financial footing and has saved the economy more than 1 percent of GDP.

KPLC'S Success in Driving Down Hidden Costs, 2001–08



Source: Briceño-Garmendia 2008.

long enough to allow parallel policy and institutional changes to be enacted and to take root. In contrast, many African governments saw them as costly reform measures needed to secure donor finance and had no intention of taking the process any further. Second, although management contracts can produce financial and efficiency gains, they cannot overcome broader policy and institutional weaknesses. Moreover, the efficiency gains do not always provide tangible improvements for customers, even though they impose substantial adjustment costs on management, making political support for these measures hard to build.

Most African power utilities remain state owned and operated. On average, Africa's state-owned power utilities embody only 40 percent of good governance practices for such enterprises (Vagliasindi and Nellis 2009). Most utilities score better on internal governance criteria, such as board structure and accountability, than on external governance criteria, such as outsourcing and labor and capital market disciplines.

The acute need to improve the management of utilities and the frameworks they operate under has long been acknowledged. Over the years, substantial sums have been spent on institutional reforms: training management, improving internal accounting and external auditing, strengthening boards of directors, providing financial and operational information, building reporting systems, creating and reinforcing supervisory and regulatory agencies, and much more. Some enduring successes have been registered (box 8.3; further discussion of institutional issues can be found in chapter 4 of this volume).

BOX 8.3

Botswana's Success with a State-Owned Power Utility

The Botswana Power Corporation (BPC) is a government-owned monopoly that produces, transmits, and distributes electrical power in Botswana. It was formed by government decree in 1970 with the objective of expanding and developing electrical power potential in the country. From its small beginnings with one power station in Gaborone and a network that extended some 45 kilometers outside the city, the power utility's responsibilities, along with the national network, have expanded enormously. The government has a regulatory role through the Energy Affairs Division of the Ministry of Minerals, Energy, and Water Affairs.

BPC increased access to power to 22 percent in 2006 and is set to reach 70 percent in 2009 and 100 percent by 2016. Through government funding, BPC is extending the electricity grid into rural areas and developing the reach of the national transmission grid. Overall, the power system operates efficiently, with system losses of no more than 10 percent and a decent return on assets.

BPC constantly weighs its options of importing against expanding its own generation facilities, taking into account both economic and strategic factors. The national system provides 132 megawatts, with the remaining 266 megawatts supplied by neighboring countries through the Southern African Power Pool. Since the pool's inception in 1995, Botswana has been a major beneficiary, and its active trading position promoted multilateral agreements among pool members, generally enhancing regional power cooperation.

Part of BPC's strong performance is thanks to cheap imported power from South Africa (now severely threatened by the power crisis). But analysts give institutional factors equal weight: a strong, stable economy; cost-reflective tariffs; lack of government interference in managerial decisions; good internal governance; and competent, well-motivated staff and management. (For a more detailed discussion of institutional reforms, see chapter 4 in this volume.)

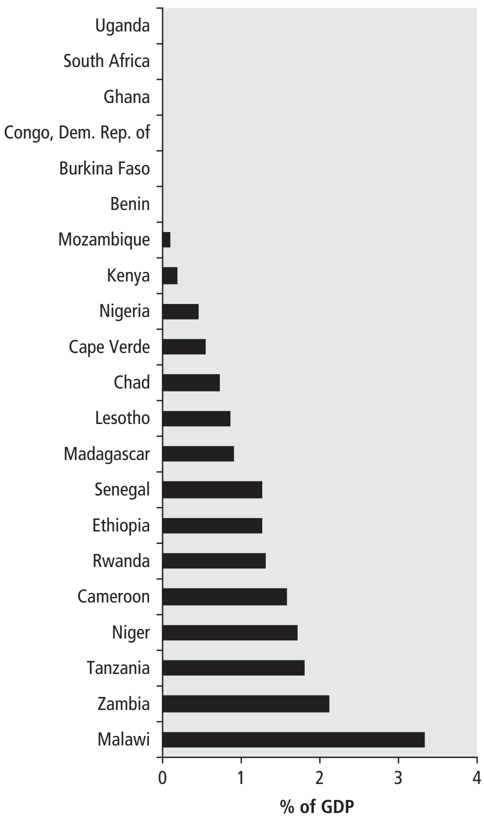
Sources: Molefhi and Grobler 2006; PPA 2005.

The Challenge of Cost Recovery

Underpricing power costs the sector at least $2.2 billion a year in forgone revenues (0.9 percent of GDP on average). Underpricing power is widespread across Africa. In the worst cases (Malawi, Tanzania, and Zambia), underpricing can result in utilities' capturing less than half of the revenues they need and creating an economic burden in excess of 2 percent of GDP (figure 8.6).

These figures probably understate the underpricing because of the difficulty of capturing subsidies to large industrial and mining customers, which are usually contained in bilateral contracts and not reflected in the general tariff structure. Key examples include the aluminum-smelting sector in Cameroon and Ghana and the mining sector in Zambia, where large strategic customers have purchased power at heavily discounted rates of just a few cents per kilowatt-hour. These arrangements were initially justified as locking in base-load demand to support very large power projects that exceeded the country's immediate demands, but they are now questionable because competing demands have grown to absorb this capacity.

Figure 8.6 Underpricing of Power in Selected Countries



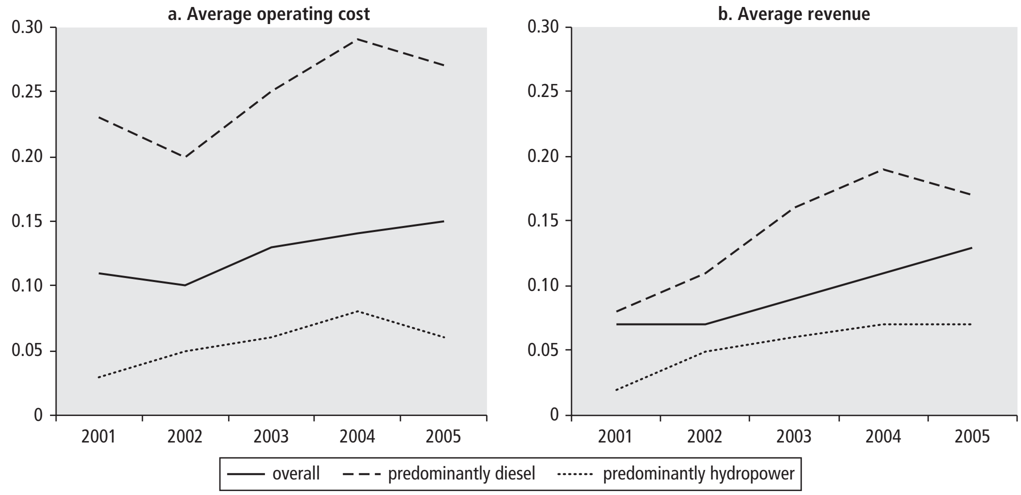
Source: Briceño-Garmendia 2008.

Power prices have risen substantially in recent years, but they have nonetheless failed to keep pace with escalating costs. Because of rising oil prices, lower availability of hydropower, and greater reliance on emergency leases, the costs of power production in Africa rose substantially in the early to mid-2000s (figure 8.7, panel a). In response, several countries have increased power tariffs, so that the average revenue of power utilities almost doubled over the same period (figure 8.7, panel b). Even so, because of historic pricing shortfalls, overall average revenues by the end of this period had barely caught up with average operating costs at the beginning of the period.

Most countries are achieving no more than operating-cost recovery. The correlation between average revenues and average operating costs across Sub-Saharan countries is as high as 90 percent, indicating that operating-cost recovery is the driving principle behind power pricing in most cases. Cameroon, Cape Verde, Chad, Malawi, Niger, Rwanda, Senegal, and Tanzania (countries under the 45-degree line in figure 8.8, panel a) fail to meet even operating-cost recovery, and several of them face particularly high operating costs (figure 8.8).

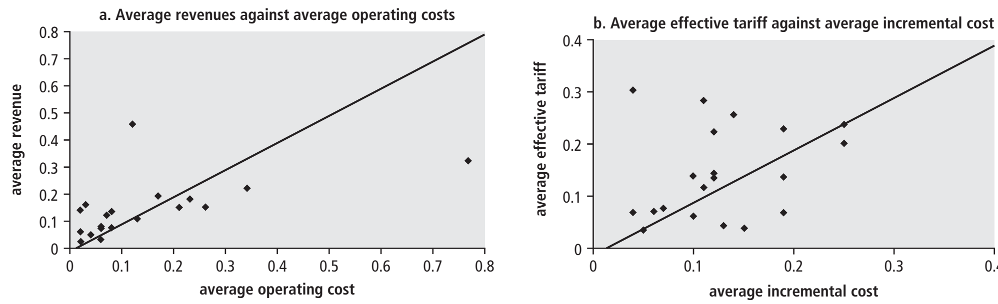
The longer-term cost-recovery situation is somewhat more hopeful. Comparing existing average revenues and average operating costs misrepresents long-term cost recovery for two reasons. First, because of major inefficiencies in revenue collection, the average *revenue* collected per unit of electricity sold is substantially lower than the average effective *tariff* charged today. Second, because of the major inefficiencies in generation technology and the potential for regional trade, for more than two-thirds of the countries the average *incremental* cost of power looking forward is lower than the average *historical* cost of power production looking

Figure 8.7 Electricity Costs and Revenues by Type of Power System, 2001–05
US$ per kilowatt-hour



Source: Briceño-Garmendia 2008.

Figure 8.8 Past and Future Cost-Recovery Situation
US$ per kilowatt-hour



Source: Briceño-Garmendia 2008.

backward and including both historic operating and capital costs.

A truer picture of long-term cost recovery comes from comparing today's average effective *tariff* with the average incremental *cost* looking forward (figure 8.8). At least in some countries, even the current tariff would be adequate for cost recovery, if only all revenues could be collected and the power system could move toward a more efficient production structure. In other countries, however, significant tariff adjustments would still be needed in the long term.

In most cases, the state or donors have almost entirely subsidized the historic capital costs of power development. Although the residential sector accounts for 95 percent of power utility customers in Africa, it contributes only around 50 percent of sales revenue. Thus, the pricing of power to commercial and industrial consumers is just as important for cost recovery. Neither commercial nor residential customers are close to paying full cost-recovery prices.

Subsidies to residential consumers are highly regressive. Across the bottom half of the income distribution, barely 10 percent of households have access to electricity (Wodon 2008). Indeed, three-quarters of the households with electricity come from the top two quintiles of the income distribution. Because poorer households are almost entirely excluded, they cannot benefit from subsidies embedded in electricity prices. In many cases, targeting performance is further exacerbated by poor tariff design, with the widespread use of increasing block tariffs that provide large lifeline blocks of highly subsidized power to all consumers.

With subsistence consumption of 50 kilowatt-hours a month, the cost of a monthly utility bill priced to recover full historic costs of production would be as much as $24.30 in central Africa, which is manifestly unaffordable for the vast majority of the population (table 8.5). Elsewhere in Africa, a subsistence monthly bill priced at full historic cost would range between $7.00 and $10.70 and would be affordable to the relatively affluent sections of the population that already enjoy access to power, but not to the poorer segments of the population that remain unconnected. Indeed, affordability of cost-recovery power bills for existing customers is today really only a problem in low-income countries reliant on small-scale, oil-based generation.

Looking into the future, pricing at the lower long-run marginal cost of power would reduce the subsistence monthly bill to the $3.00–$4.00 range in central and southern Africa where abundant low-cost hydropower would become available (table 8.5). Such modest bills would be affordable to all but the poorest 25 percent of the population. In eastern and western Africa, the subsistence monthly bill would fall in the $7.00–$9.00 range. Although this amount would likely be affordable for existing customers, it would represent a problem as power access is expanded to lower-income populations. When a more efficient power system develops, full cost-recovery tariffs would be affordable for the vast majority, except perhaps in West Africa.

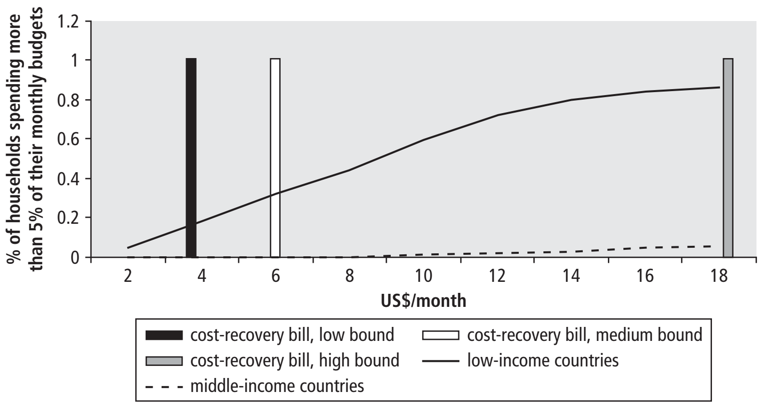
If regional trade is pursued, the average costs of power production could be expected to fall toward $0.07 in central and southern Africa, $0.12 in eastern Africa, and $0.18 in western Africa. Assuming, again, subsistence consumption of 50 kilowatt-hours a month, a monthly utility bill under full cost-recovery pricing would be about $4 a month in central and southern Africa, $6 a month in eastern Africa, and $9 a month in western Africa. Based on an affordability threshold of 3 percent of household income, full cost-recovery tariffs would prove affordable for the vast majority of the population of low-income countries in central, eastern, and southern Africa (see figure 8.9). In West Africa, about half the population of the low-income countries would face affordability problems. A number of West African countries—notably Côte d'Ivoire,

Table 8.5 Cost and Affordability of Monthly Power Bills at Cost-Recovery Prices: Past and Future
$ per month

Location	Historic cost	Long-run marginal cost
Central African Power Pool	24.30	3.50
East African Power Pool	9.50	7.00
Southern Africa Power Pool	7.00	3.00
West Africa Power Pool	10.70	9.00

Source: Derived from Rosnes and Vennemo 2008.
Note: Dark gray shading: power bill is unaffordable to the vast majority of the population; light gray shading: power bill is affordable to existing customers only, who are typically the richest 25 percent of the income distribution; no shading: power bill is affordable to all but the poorest 25 percent of the income distribution.

Figure 8.9 Affordability of Subsistence Consumption of Power at Cost-Recovery Pricing



Source: Banerjee and others 2008.
Note: A power bill for subsistence consumption of 50 kilowatt-hours per month is considered affordable if it absorbs no more than 5 percent of household income.

Ghana, Nigeria, and Senegal—already have power coverage of around 50 percent and would face affordability issues as coverage broadens. At any of these levels, power tariffs do not represent a significant affordability issue in the middle-income countries. (For a fuller discussion of the social issues associated with utility pricing in Africa, see chapter 3 in this volume.)

Policy Challenges

The depth and extent of Africa's power crisis and its associated costs demand renewed efforts to tackle the policy and institutional challenges needed to improve performance and financing. The key challenges can be characterized as follows:

- Strengthening sector planning
- Recommitting to the reform of SOEs
- Increasing cost recovery
- Accelerating electrification
- Expanding regional trade in power
- Closing the financing gap.

These interdependent challenges must be dealt with simultaneously. Efforts to boost generation through regional power trade will stumble if the utilities, which will continue to be central actors, remain inefficient and insolvent. Expanding electricity distribution systems without addressing the shortages in generation and improving transmission capacity would clearly be futile. In addition, focusing exclusively on utility reform would be fruitless without a start on substantial, long-gestation investments in both generation and access to improve the quality of service and make the utilities viable. In short, these strategic priorities must progress together.

Strengthening Sector Planning

Most African power markets present an institutional "hybrid," with public and private actors operating in parallel. The 1990s reform prescription of unbundling and privatization, leading to wholesale and retail competition, did not prove very relevant to Africa, not least because most of the region's power systems are simply too small to support any meaningful competition. The new reality is thus one of "hybrid markets," with the state-owned utility remaining intact and occupying a dominant market position. At the same time, because many governments and utilities lack sufficient investment resources, the private sector participates, typically as IPPs. Africa's hybrid electricity markets pose new challenges in policy, regulation, planning, and procurement. The widespread power shortages across the continent and the increasing reliance on emergency power indicate the seriousness of those challenges.

Too often, the planning function has fallen between the cracks. Traditionally, planning and procurement of new power infrastructure were the province of the state-owned utility. With the advent of power sector reforms and the IPPs, those functions were often moved to the ministry of energy or electricity. A simultaneous transfer of skills did not always occur, however, resulting in plans that were not adequately informed by the complexities on the ground: a new hybrid market of private and public actors. In many cases, planning has collapsed. Where still present, planning tends to take the form of outdated, rigid master plans. The lack of strategic policy and planning for the electricity sector at the central government level is a critical weakness. Interventions have been piecemeal rather than integrated; many countries have focused on generation without investing in efficient transmission and delivery of power.

This situation has led to very costly delays in commissioning new plants. In the absence of strong political leadership, good information, and the requisite planning capability, incumbent state-owned utilities often undermine the entry of IPPs by arguing that they can supply power more cheaply or quickly than private alternatives, even if they lack the resources to do so. Poor understanding of the hybrid market deprives policy makers of clear and transparent criteria for allocating new plants between the incumbent, state-owned utility and the IPPs. New plants are rarely ordered on a timely basis, thereby opening power gaps that prompt recourse to temporary power and discourage investors. When procurement is (finally) undertaken, the authorities may not take the trouble to conduct international competitive bidding. This outcome is unfortunate, because a rigorous bidding process lends credibility and transparency to procurement and results in more competitively priced power.

Restoring and strengthening planning capabilities are imperative. Hybrid power markets will not disappear from the African landscape any time soon. To make the best of them, African governments and their development partners must strive to develop a robust institutional foundation for the single-buyer model, with clear criteria for power purchase (off-take) agreements and dispatches of power under those agreements. Governments must restore a strong sector planning capability at the line ministry level, establish clear policies and criteria for allocating new plant opportunities between the state-owned utilities and IPPs, and commit to competitive and timely bidding processes. A well-articulated plan for the sector will allow governments to move beyond the "firefighting" that has reduced their ability to anticipate exogenous shocks, such as drought or high oil prices.

Development partners need to tread carefully in the hybrid marketplace. They can help by providing advice on transparent contracting frameworks and processes and by lending expertise to governments and utilities as the latter seek to reach financial closure with project sponsors and private investors. Lending to public utilities needs to be handled carefully; if done without adequate attention to the peculiarities of the hybrid market, it may have the unintended effect of deepening the contradictions inherent in those markets and even crowding out private investment. What is needed above all is to strengthen public institutions to enable them to engage effectively with the private sector.

Recommitting to the Reform of State-Owned Enterprises

Renewed efforts on SOE reform should favor governance over technical fixes. State-owned utilities are still prevalent across Africa, and their performance is generally poorer than in other regions. Fortunately, improving the governance of SOEs can improve performance. Past efforts at improving utility management focused too heavily on technical issues to the exclusion of governance and accountability. Future SOE reforms seem justified as long as they focus on these deeper institutional issues.

The starting point for SOE reform should be to reform corporate governance. Key measures include greater decision-making autonomy for the board of directors, more objective selection criteria for senior managers, and rigorous disclosure of conflicts of interest, as well as more transparent and merit-based recruitment processes.

Parallel efforts are needed to strengthen financial and operational monitoring of SOEs by their supervisory agencies, whether they are line ministries or ministries of finance. Transparency and accountability of SOEs depend on solid financial management, procurement, and management information systems. Today, basic operational and financial data on firm performance are not produced, reported, or acted on. Without information or, perhaps worse, without action based on whatever information is produced, better outcomes cannot be expected. Key measures include auditing and publishing financial accounts and using comprehensive cost-based accounting systems that allow functional unbundling of costs and a clearer sense of cost centers.

In principle, regulation can be an important part of this process, but in practice, it proves challenging to develop. Electricity regulators have been set up across Africa, precisely to insulate utilities from political interference while closely monitoring enterprise performance. Some critics argue that regulatory agencies have simply created additional risks because of their unpredictable decisions, resulting from excessive discretion and overly broad objectives. Moreover, regulatory autonomy remains elusive; in some countries, turnover among commissioners has been high, while the gap between law (or rule) and practice is often wide. The challenge of establishing new public institutions in developing countries is often underestimated. Independent regulation requires a strong political commitment and competent institutions and people. Where some or all are lacking, it seems wise to consider complementary or transitional options that reduce discretion in regulatory decision making through more explicit rules and procedures, or outsourcing the regulatory functions to advisory regulators and expert panels (Eberhard 2007).

When this foundation is in place, contracting mechanisms can be used to improve performance. These mechanisms could be performance contracts in the public sector or management contracts with the private sector.

Public sector performance contracts need to incorporate strong performance incentives. Initial attempts to improve African SOEs through performance contracts with the line ministry or other supervisory agency were minimally effective. Recent efforts in the water sector (in Uganda, for example) have had a stronger and much more positive effect. The key feature of these contracts is to incorporate incentives for good managerial (and staff) performance and, more rarely, sanctions for failure to reach targets. This approach to more comprehensive performance contracts deserves further consideration.

Creating effective performance incentives within a public sector context can be quite challenging. Management contracts with the private sector are thus a relevant option. They can be applied with either expatriate or local management teams, each of which offers advantages. Nonetheless, clarity about what they can and cannot achieve, particularly given their short time horizons, is important. At best, a management contract can improve performance on a handful of manageable aspects of efficiency, such as revenue collection and labor productivity. It cannot solve deficiencies in the broader institutional framework, which ideally should be addressed earlier. Nor can a management contract raise investment finance or significantly affect service quality if substantial investments or long gestations are required.

Utilities that have the institutional basics in place would likely benefit from technical assistance (box 8.4). In particular, operational efficiency programs are needed to reduce the high rates of technical, nontechnical (electricity theft), and collection losses. Such programs can include capacity building and technical assistance to improve management, business practices, and planning. The priorities are improved load management (to better match supply with priority customer needs), theft reduction initiatives, and increased revenue collection (through enhanced metering and better-run customer service units). Capital spending can also be reduced by using low-cost

BOX 8.4

CREST Spreading Good Practices

The Commercial Reorientation of the Electricity Sector Toolkit (CREST) is an experiment under way in several localities served by West African electricity providers. Based on good practices from recent reforms in Indian, European, and U.S. power corporations, CREST is a "bottom-up" approach for attacking system losses, low collection rates, and poor customer service.

To accomplish its objectives, CREST uses technical means (replacing low-tension with high-tension lines, for example, and installing highly reliable armored and aerial bunched cables on the low-tension consumer point to reduce theft) and managerial changes (introducing "spot billing" and combining data recording, data transfer, bill generation, and bill distribution). Transaction times are reduced, and cash flows improve. Early applications of CREST have reportedly produced positive changes in several neighborhoods in Guinea and Nigeria, two difficult settings.

Source: Based on interviews with World Bank staff from the Africa Energy Department, 2008.

technology standards, as in Guinea and Mali. Innovations have included adjusting technical design standards to meet the reduced requirements of low-load systems, maximizing the use of material provided by local communities (such as locally sourced wooden poles), and recruiting employees and supervisors from the local community.

Finally, institutional change is a long-term matter, but well worth the wait. Victories on this front will be small and slow in coming. Donors may prefer the large and the quick, but they must recognize that positive changes in this field lie at the heart of African power sector reform.

Increasing Cost Recovery

The financial viability of incumbent utilities is a key foundation of a healthy power sector. Financially viable utilities are more effective operationally, because they are able to finance timely maintenance activities. They are also more creditworthy and thus may begin to secure their own access to domestic or international capital markets. Achieving this goal demands power tariffs that are high enough to cover operating costs and to contribute as much as possible to covering capital costs as well.

Cost recovery already looks feasible in countries with relatively low-cost domestic power sources. In the continent's larger countries, and in those that rely on hydropower and coal-based generation, cost-recovery tariffs already appear affordable for the majority of the population, and certainly for the affluent minority that enjoys access to power. A case thus exists for these countries seriously to consider moving closer to full cost recovery.

For countries with high-cost domestic power, cost recovery may become feasible in the medium term as regional trade develops. In the continent's smaller countries, and those reliant primarily on oil-based generation, cost-recovery tariffs are largely unaffordable. As regional trade develops and access to more cost-effective sources of power generation open up, however, the total cost of power production will fall, making cost recovery a much more reasonable goal in the medium term. (The possible exception is West Africa, where the costs of power will remain relatively high even with regional trade.) A case thus exists for these countries to start moving their tariffs toward longer-term cost-recovery levels, accepting that the sector will continue to register financial deficits in the short term.

Cost recovery is particularly important for emergency power leases, to avoid diverting budgetary resources from long-term investments. Numerous African countries have responded to the power crisis by leasing emergency power generation. This solution is rapid and effective but simultaneously costly and temporary. Charges typically amount to $0.20–$0.30 per kilowatt-hour, without considering transmission and distribution costs or associated losses. Given that the cost of backup generation for the private sector is approximately $0.40 per kilowatt-hour, and that the value of lost load may well be higher than that, the private sector should be willing to pay the full cost of this emergency power. Nevertheless, when emergency power is provided without any adjustment to power tariffs, the resulting fiscal drain can be very large, diverting scarce resources from the investments needed to provide a longer-term solution to the power problem. To avoid this fiscal drain, utilities must price emergency power at cost-recovery levels for nonresidential customers.

Power subsidies will still be needed, but they should be well targeted and focus initially on expanding access. Existing power subsidies are captured largely by higher-income groups and do little to broaden access to electricity. Redesigning power subsidies would free scarce fiscal resources that could be redirected to subsidize the expansion of power networks to serve lower-income rural and periurban communities, or for other poverty-alleviation programs. In some of Africa's poorest countries, even low-cost power will remain unaffordable for a significant minority of the population, so well-targeted subsidies would be needed as part of the strategy for reaching universal access. What is clearly untenable, however, is the situation where power subsidies that benefit only a privileged minority of the population create a significant fiscal drag on the economy.

Accelerating Electrification

From a social and political perspective, expanding access is imperative. Yet financing expansion to lower-income households will further strain the financial viability of the power sector. Tackling this dilemma will require significantly higher concessional financing from development partners for access programs, as well as improved financial and operational performance from utilities.

Given the scale of investments needed, a systematic approach to planning and financing new investments is critical. The current ad hoc project-by-project approach in development partner financing has led to fragmented planning, volatile and uncertain financial flows, and duplicated efforts. Engagement across the sector in multiyear programs of access rollout, supported by multiple development partners as part of a coherent national strategy, will channel resources in a more sustained and cost-effective way to the distribution subsector. Coordinated action by development partners will also reduce the unit costs of increasing access, by achieving economies of scale in implementation.

Completing the urban electrification process requires careful attention to the social issues raised. Chapter 3 of this volume found that approximately half of the nonelectrified urban population lives in proximity to the grid. Densification is thus a key challenge. Demand-side barriers, including high connection charges and insecure tenure, need to be addressed as part of this process. Expansion into periurban slums will need to face power theft, for which technical fixes are available (see box 8.4).

For rural electrification, emerging evidence favors more centralized approaches (Mostert 2008). Countries with dedicated rural electrification funds have higher rates of electrification than those without. Of greatest interest, however, are the differences among the countries with funds. Case studies indicate that the countries that have taken a centralized approach to electrification, with the national utility responsible for extending the grid, have been more successful than those that followed decentralized approaches, where a rural electrification agency attempted to recruit multiple utilities or private companies into the electrification campaign. Therefore, expecting specialized agencies to solve the rural electrification challenge on their own may be unrealistic. They may be most productive in promoting minigrids and off-grid options as extensions of the national utility's efforts to extend the grid, as in Mali (box 8.5).

Rural electrification may need to follow urban electrification. In an African context, one can legitimately ask how far rural electrification can progress when the urban electrification process is still far from complete. Across countries, a strong correlation exists between urban and rural electrification rates, as well as a systematic lag between the two. Countries with seriously underdeveloped generation capacity and tiny urban customer bases are not well placed to tackle rural electrification, either technically because of power shortages or financially because of the lack of a basis for cross-subsidization.

Finding ways of spreading the benefits of electrification more widely is also important. Because universal household electrification is still decades away in many countries, sectorwide programmatic approaches need to ensure that the benefits of electrification touch the poorest households that may be too far from the grid or just unable to pay for a grid connection. Street lighting may be one way of doing that in urban areas. In rural areas, solar-powered electrification of clinics and schools that provide essential public services to low-income communities is another way of allowing them to participate in the benefits of electrification. Another is appropriate technology, such as low-cost portable solar lanterns that are much more accessible and affordable to the rural public. The Lighting Africa initiative is supporting the development of the market for such products.

Expanding Regional Trade

A strategic priority is to tackle head-on the generation capacity deficit through major

BOX 8.5

Rural Electrification in Mali

Among new African rural electrification agencies, AMADER (Agence Malienne pour le Développement de l'Énergie Domestique et l'Électrification Rurale, or Malian Agency for the Development of Domestic Energy and Rural Electrification) has had considerable success. The starting point for AMADER is a country in which only about 3 percent of the rural population has access to electricity. Until they are connected, most rural households meet their lighting and small power needs with kerosene, dry cells, and car batteries, averaging monthly household expenditure of $4–$10.

Created by law in 2003, AMADER uses two major approaches to rural electrification: (a) spontaneous, "bottom-up" electrification of specific communities and (b) planned, "top-down" electrification of large geographic areas. The bottom-up approach, which typically consists of minigrids managed by small local private operators, has been more successful. By late 2008, about 41 bottom-up projects had been financed, comprising 36,277 household connections at an average cost per connection of $776. Typically, AMADER provides grants for about 75 percent of the connection capital costs.

Because Mali has limited renewable resources, most of the minigrid systems are diesel fired. Customers on these isolated minigrids typically receive electricity for six to eight hours a day. In promoting these new projects, AMADER performs three main functions: it acts as a (a) provider of grants, (b) supplier of engineering and commercial technical assistance, and (c) de facto regulator through its grant agreements with operators. The grant agreement can be viewed as a form of "regulation by contract" that establishes minimum technical and commercial quality of service standards and maximum allowed tariffs for both metered and unmetered customers.

To ensure that the projects are financially sustainable, AMADER permits operators to charge residential and commercial tariffs that are higher than the comparable tariffs charged to similar customers connected to the national grid. For example, the energy charge for metered residential customers on isolated minigrids is about 50 percent higher than the comparable energy charge for grid-connected residential customers served by Énergie du Mali (the national electric utility). Many of the minigrid operators also provide service to unmetered customers, who are usually billed a flat monthly charge per lightbulb and outlet, combined with load-limiting devices to ensure that a customer does not connect lightbulbs and appliances beyond what he or she has paid for.

Financing has been a problem for both AMADER and potential operators. AMADER has been hindered by insufficient and uncertain funding for providing capital cost grants. Potential operators have had difficulty raising equity or obtaining loans for the 20–25 percent share of capital costs not funded by AMADER. Promoting leasing arrangements and instituting a loan guarantee program for Malian banks that would be willing to lend to potential operators have been discussed as methods of reducing financial barriers for operators.

Source: Based on interviews with World Bank staff from the Africa Energy Department, 2008.

regional projects. Africa's considerable hydropower, gas, and coal resources remain underexploited. The best way to scale up generation at the lowest unit cost is to develop a new generation of large power generation projects. A substantial number of these transformational projects should be developed in the near term to begin to make a material difference on the supply-demand balance. However, individual countries do not have the necessary investment capital, or even the electricity demand, to move forward with these large projects. A project finance approach predicated on regional power off-take is needed, blending private participation and donor funding.

Power pool development must proceed in parallel so that this new capacity can be transmitted to users. Challenges common to all the pools are rehabilitating and expanding the cross-border transmission infrastructure to increase the potential for trade and harmonizing regulations and system operating agreements. Equally important is formulating market trading mechanisms so that the additional energy generated from large projects can be priced and thus allocated efficiently and fairly (for example, through competitive pool arrangements).

Although the economics of large regional generation projects are convincing, they may give rise to significant political challenges. Africa could potentially save $2 billion a year in energy costs if trade were pursued to its fullest desirable extent, but the gains are much larger for some countries than for others. Small thermal power–dependent countries and a handful of major exporters are likely to benefit the most. About one-third of African countries would end up importing more than half of their power needs, and self-sufficiency sometimes has more political weight than access to low-cost power.

Moreover, reaping the benefits of regional power trade essentially depends on realizing massive investments in three challenging countries. The Democratic Republic of Congo, Ethiopia, and Guinea would be the major power exporters under a regional trading system. To become major exporters, however, all three would need to invest massively in hydropower, which could easily absorb more than 8 percent of their GDP for a decade. Even with support from cross-border finance, the limited financial capacity of these countries and the numerous governance challenges faced by the fragile states (the Democratic Republic of Congo and Guinea) make this quite a tall order.

These considerations call for an incremental approach to developing regional trade. The initial emphasis needs to be on quick wins by building bilateral exchanges between neighbors where a particularly strong economic case exists and where the political context is supportive. This strategy will allow trading experience to build up gradually, paving the way for adding more complexity over time. Even if Africa's first-best generation options cannot always be developed or if the ultimate pattern of power production on the continent turns out to be driven more by financial muscle than by economic expansion, the benefits of interconnection remain clear. Given the small scale and undiversified nature of most countries' power systems, cross-border transmission will always make sense as a means of boosting the efficiency and reliability of power production.

Closing the Funding Gap

Africa's power funding gap is particularly daunting, even more so in the global financial crisis. At $23 billion, the funding gap in Africa's power sector is the largest of any infrastructure sector. The global financial crisis will likely exacerbate the problem. As noted earlier, slower growth could reduce spending needs by as much as 20 percent, but tighter global financial markets could similarly reduce available funding, widening the funding gap even further.

Improving creditworthiness is an important first step that could eventually assist in accessing capital markets. The immediate subsidy savings from addressing operational efficiencies and cost recovery, though substantial, do not come close to closing the gap. In principle, utilities achieving operational efficiency and cost recovery (whether state owned or privately run) could aspire to raising their own capital on domestic or international markets, but that ability is still some way off. External finance to Africa's power sector had been very low for some time but has picked up in recent years (figure 8.10).

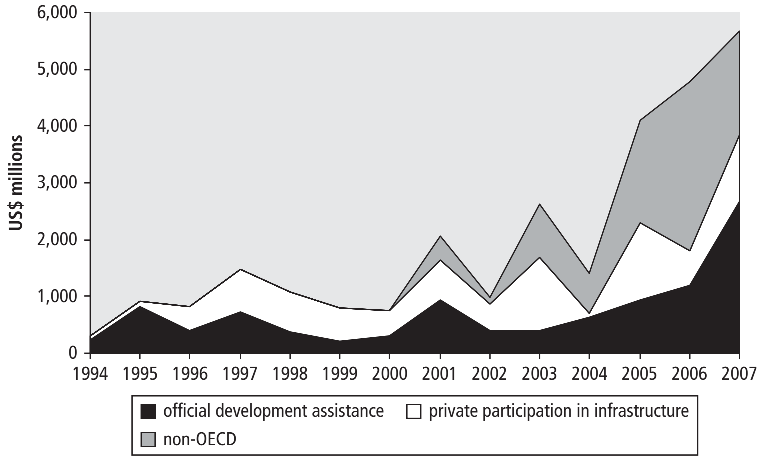
Official development assistance to public investment in power has risen substantially. In response to the power crisis, donors have increased their emphasis on the power sector. Commitments averaged $1.5 billion a year for 2005–07, reaching a peak of $2.3 billion in 2007. This is an important turnaround in funding, but more will be needed if any substantial inroads are to be made into Africa's power sector challenges.

Non-OECD countries have emerged as major new power financiers in Africa (Foster and others 2008). Commitments of non-OECD countries, particularly the Chinese and Indian export-import banks, came from nowhere to average about $2 billion a year in 2005–07. Most of the Chinese financing has gone to 10 large hydropower projects with a combined generating capacity of over 6,000 megawatts. Once completed, these projects will increase Sub-Saharan Africa's installed hydropower capacity by 30 percent. China is also financing 2,500 megawatts of thermal power, and the Indian Bank has financed significant thermal generation projects in Nigeria and Sudan.

Private finance was also buoyant until 2007, but significantly lower than official finance. Private commitments to Africa's power sector averaged about $1 billion a year in 2005–07, putting it in third place behind non-OECD finance and traditional official development assistance. The bulk of private resources has gone into 3,000 megawatts of independent power projects. Although it will not be enough to close the financing gap, private finance is very much needed. Successful private investments in energy projects in Africa are still rare, however, and increased private investment will not materialize simply because of large financing gaps. The lessons from past failures must be addressed because private investment will flow only where rewards demonstrably outweigh risks. Some early but encouraging signs indicate that scaling up generation capacity through large private sector–led projects is starting to gather momentum. A prominent example is the privately owned 250-megawatt Bujagali hydropower plant in Uganda, supported by World Bank Group guarantees and funded by a private consortium. Ambitious regional projects undoubtedly present technical, financing, and political risks and will continue to be underpinned by substantial public sector and donor contributions.

Shorter-term measures on energy efficiency can ease the transition. Most of the measures described here are medium term and cannot be implemented overnight. Many Sub-Saharan countries will continue to face a very tight demand-supply balance in the coming years. Therefore, shorter-term measures to soften the economic and social effects of power scarcity must complement longer-term efforts at addressing the underlying structural causes of the power supply crisis. Recent experiences from countries such as Brazil show that well-designed demand-side management measures (for example, a quota system with price signals, combined with a public energy-efficiency campaign) can go a long way toward trimming peak demand, substantially reducing power rationing at fairly low economic and social cost.

Figure 8.10 External Financing Commitments for the African Power Sector, 1994–2007



Source: Briceño-Garmendia, Smits, and Foster 2008.
Note: OECD = Organisation for Economic Co-operation and Development.

Notes

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1. Isolated areas are more than 50 kilometers from a substation and are either in the power plant buffer (within 10 kilometers for capacity below 10 megawatts, 20 kilometers for capacity below 100 megawatts, and 50 kilometers for capacity below 100 megawatts) or within 10 kilometers of a lit urban area or lit pixel. Remote areas are more than 50 kilometers from a substation and are not in the power plant buffer or within 10 kilometers of a lit urban area or lit pixel.
2. These costs are calculated at the consumption level of 100 kilowatt-hours a month.

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