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# Financial Viability of Electricity Sectors in Sub-Saharan Africa

## Quasi-Fiscal Deficits and Hidden Costs

*Chris Trimble*
*Masami Kojima*
*Ines Perez Arroyo*
*Farah Mohammadzadeh*

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## Abstract

This paper studies the financial viability of electricity sectors in 39 countries in Sub-Saharan Africa using an approach similar to that in an earlier study, the Africa Infrastructure Country Diagnostic. The quasi-fiscal deficit in each country is calculated under two scenarios: existing utility performance and benchmark utility performance. In the first scenario, only two countries have a financially viable electricity sector (the Seychelles and Uganda). Only 19 countries cover operating expenditures, while several countries lose in excess of US$0.25 per kilowatt-hour sold. Quasi-fiscal deficits average 1.5 percent of gross domestic product, and exceed 5 percent of gross domestic product in several countries. In this context, it will be difficult for utilities to maintain existing assets let alone facilitate the expansion needed to reach universal access goals. The number of countries with a quasi-fiscal deficit below zero increases to 13 under the second scenario, and to 21 when oil price impacts are considered, indicating tariff increases may not be needed at benchmark performance in these cases. Combined network and collection losses on average represent a larger hidden cost and are less politically sensitive to address than underpricing, so could be a smart area for policy focus to reduce quasi-fiscal deficits. Underpricing remains an issue to address over the medium term, as service quality improves. With no changes in power mix, tariffs would need to increase by a median value of US$0.04 per kilowatt-hour sold at benchmark performance, representing a 24 percent increase on existing tariffs. Most countries have improved or maintained performance, and relatively few countries have had declining financial viability.

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## Abbreviations

| | |
|---|---|
| AICD | Africa Infrastructure Country Diagnostic |
| capex | capital expenditure |
| CEB | Communauté Electrique du Bénin |
| CIE | Compagnie Ivoirienne d'Electricité |
| EdM | Electricidade de Moçambique |
| EPP | emergency power producer |
| GDP | gross domestic product |
| GW | gigawatt(s) |
| GWh | gigawatt-hour(s) |
| HFO | heavy fuel oil |
| HV | high voltage |
| IAS | International Accounting Standards |
| IFRS | International Financial Reporting Standards |
| IPP | independent power producer |
| Ketracp | Kenya Electricity Transmission Company |
| km | kilometer(s) |
| KPLC | Kenya Power and Lighting Company |
| kV | kilovolt(s) |
| kW | kilowatt(s) |
| kWh | kilowatt-hour(s) |
| LHWC | Lesotho Highlands Water Commission |
| LV | low voltage |
| Motraco | Mozambique Transmission Company |
| MW | megawatt(s) |
| MV | medium voltage |
| MYTO | Multi-Year Tariff Order |
| O&M | operations and maintenance |
| OMVS | Organisation pour la Mise en Valeur du fleuve Sénégal |
| OMVG | Organisation pour la Mise en Valeur du fleuve Gambie |
| opex | operating expenditure |
| QFD | quasi-fiscal deficit |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SE4ALL | Sustainable Energy for All |
| SPV | special-purpose vehicle |
| SSA | Sub-Saharan Africa or African |
| T&D | transmission and distribution |
| VAT | value-added tax |
| WACC | weighted average cost of capital |
| ZESCO | Zambia Electricity Supply Company |

# 1 Context

Electricity sectors in Sub-Saharan Africa (SSA) lag behind all other regions of the world. Installed capacity of power generation for the entire continent is less than that of Spain, over 600 million people lack access to electricity, and power consumption of 375 kilowatt-hours (kWh) per capita per year is low by any standard. The results are frequent load-shedding, expensive short-term rental of emergency power generation, and, in nearly all cases, high reliance on costly diesel for off-grid captive power generation even in large cities.

Progress toward universal access is slow. According to the SE4ALL Global Tracking Framework (SE4ALL 2015a), access to electricity in the region in 2012 was only 35 percent, having increased from 26 percent in 2000. With per capita gross domestic product (GDP) of US$3,274 in the same year measured in current dollars at purchasing power parity (World Bank 2016a), this low access rate in part reflects the inability of many households to pay for electricity. That said, by contrast, when South Asia was at the same level of this measure of GDP per capita in 2005–2006, its rate of access was already double that in SSA. The rural/urban population divide in the two regions are comparable, with the rural population making up 68 percent of the total in South Asia and 64 percent in SSA in 2012 (although population density is likely to be lower in SSA). The largest difference was in the rural access rates: a mere 15 percent in SSA in 2012, against more than triple that in South Asia in 2005–2006.

The low access rates in many countries in SSA mean that electricity customers today are relatively well-off, and yet in 2013 less than 20 percent of utilities reported a net profit. As noted in Dobozi (2016), the main cause of the slow progress in access expansion in SSA is the poor financial viability of electricity utilities. The sector needs substantial capital infusion. The annual cost of addressing SSA's power sector needs has been estimated at US$41 billion, including US$14 billion for new power generation additions (Eberhard et al. 2011). Other estimates have suggested US$17 billion of investments a year are needed just to achieve universal access targets (SE4ALL 2015a). Whether US$14 billion or US$17 billion, these investment requirements contrast with an estimated US$3 billion's worth of new capacity coming on stream in 2013 found in this study. Although there are many reasons for this gap, poor sector fundamentals—policy, regulatory, and contractual framework meeting international benchmarks; enforcement of regulations and policies in place; the payment discipline of all parties; and the financial viability of utility operation—are largely responsible. And despite large financial gaps between the cost of service and cash collected, electricity consumers in SSA do not necessarily enjoy low tariffs. If anything, tariffs in the region are relatively high for a variety of reasons: small economies of scale, low concentrations of high-volume consumers with good payment discipline, continuing reliance on oil-based generation, and high operational inefficiencies.

Due to continuing financial shortfalls, not only is the power sector in most SSA countries unable to expand supply to new consumers at the desired pace, it cannot deliver reliable electricity to the existing ones. Acute power shortages act as a brake on economic growth. In surveys of firms in the region, 38 percent identified electricity as a major constraint to doing business and 50 percent reported owning or sharing a back-up generator. On average, firms reported losing 8.6 percent of the total annual sales due to power outages (Enterprise Surveys 2016). A new index ranging from 0 to 8 for supply reliability and tariff transparency tabulated by *Doing Business* found SSA to have the lowest index, 0.9, against 1.9 in South Asia, 3.6 in East Asia and the Pacific, and an average of 7.2 among the high-income member countries of the Organisation for Economic Co-operation and Development (Doing Business 2016). The majority of countries in SSA have long experienced serious power shortages, resulting in load-shedding and frequent interruptions to service. The economic costs of power outages, including the costs of running backup generators and of forgone production, typically range between 1 and 4 percent of GDP (Foster and Briceño-Garmendia 2010). Infrastructure problems, and notably deficient power generation and transmission infrastructure, have been estimated to account for 30–60 percent of overall drains on firm productivity, well ahead of red tape, corruption, and other factors (Escribano, Guasch, and Pena 2008).

The analysis and measurement of the "hidden costs" of state enterprises (particularly in the power sector) derives from the International Monetary Fund's concern with the quasi-fiscal activities occurring in countries of the former Soviet Union. Quasi-fiscal activities can be thought of as those operations that "could in principle be duplicated by specific budgetary measures in the form of an explicit tax, subsidy or other direct expenditure" (Mackenzie and Stella 1996). It was feared that the substantial quasi-fiscal activities observed in these countries could have large macroeconomic effects as governments were forced to intervene to finance these activities. In the former Soviet Union countries the energy sectors were becoming a source of large public sector imbalances and financial instability, and Petri, Taube, and Tsyvinski (2002) noted that low energy prices and the toleration of payment arrears were particularly prevalent in these countries. They developed a methodology to value various aspects of the quasi-fiscal activities and applied it to the energy sector in Azerbaijan and the gas sector in Ukraine. A similar analysis for the power and water sectors in Ghana was carried out by Chivakul and York (2006).

Saavalainen and ten Berge (2006) and Ebinger (2006) extended the approach of Petri, Taube, and Tsyvinski to provide estimates of the quasi-fiscal deficits (QFDs) of the power sectors in countries in Europe and Central Asia. Saavalainen and ten Berge defined the QFD of state-owned public utilities as

> *[t]he value of the implicit subsidy computed as the difference between the average revenue charged and collected at regulated prices and the revenue required to fully cover the operating costs of production and capital depreciation*.[1]

This QFD, or implicit subsidy, was termed a hidden cost[2] by Ebinger. Not all the elements of the QFD relate to a monetary cost being too large. For example, a low rate of bill collection is a cost in the sense of a loss of revenue. For the set of 20 countries analyzed by Ebinger based on 2003 data, underpricing accounted for 67 percent of total hidden costs, excess transmission and distribution (T&D) losses for 22 percent, and poor bill collection for 11 percent. Total hidden costs declined from 5.4 percent of GDP in 2000 to 2.6 percent in 2003.

The approach of Ebinger was utilized in the Africa Infrastructure Country Diagnostic (AICD), a knowledge program that undertook extensive data collection in the 2000s (primarily between 2001 and 2008) in all key infrastructure sectors, including electricity (http://www.infrastructureafrica.org/). Recognizing that the weak infrastructural base in SSA is constraining economic growth, the AICD estimated the magnitude of the QFDs for the power sector in SSA.

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[1] This definition assumes that the costs of production are the same in the hypothetical case of efficient operation and the actual case. The difference in revenues then measures the QFD.

[2] The term hidden cost is used in other contexts for the energy sector. For example, in the evaluation of externalities of power generation (Biegler 2009), and of costs of power cuts and battery backups (Seetharam et al. 2013).

The power sector was in the midst of a crisis, with tariffs that were double those in other developing regions and unreliable supply throughout the continent. The AICD calculated investment requirements for the next decade in the sector in 43 countries. A subset of the countries numbering 26—which together accounted for about 85 percent of the region's population, GDP, and infrastructure inflows—were analyzed for hidden costs of power utilities arising from underpricing and operational inefficiencies (system losses, collection inefficiencies, and overstaffing).

The AICD used two different methods. The first, as reported in Eberhard et al. (2008) and in Briceño-Garmendia, Smits, and Foster (2008), allocated hidden costs to underpricing, excess T&D losses, and incomplete bill collection. The second, as reported in Eberhard et al. (2011) and Briceño-Garmendia and Shkaratan (2011), introduced a further hidden cost, that of overstaffing. The AICD found that power utilities in SSA had large numbers of employees per customer when compared to other developing countries, suggesting that the same output might be produced with less labor.

In half the sample countries, the largest single contributor to the hidden costs was underpricing, followed by under-collection of bills (7 countries) and system losses (5 countries). Overall, these three components were more significant than overstaffing in many cases, but the latter exceeded the rest combined in Chad, underpricing in Mozambique, and T&D losses in Benin and Cape Verde, and exceeded under-collection and matched underpricing in the Republic of Congo.

Where time-series data were collected, hidden costs changed markedly over time in several countries. For example, in Ghana, the Volta River Authority's hidden costs grew from 14 percent of the total revenue in 2004 to 117 percent in 2006, halved in 2007, and then rose to 87 percent in 2008, whereas those for the Electricity Company of Ghana varied between 42 percent and 70 percent during the same period. On average, tariffs were below the cost-recovery levels, resulting in annual forgone revenue of US$3.6 billion.

Using the most recent data available, this paper updates the analysis of hidden costs carried out by the AICD and expands country coverage. The study broadly follows the methodology used in the publication by Eberhard et al. (2011), which breaks down hidden costs into underpricing, T&D losses, under-collection of bills, and overstaffing. The study asks the following questions:

- What is the status of the financial viability of electricity sectors in SSA? What is the magnitude of electricity-sector QFDs?
- What are the priority areas in individual countries for reducing costs and increasing cost recovery?
    - What is the likely magnitude of tariff increases needed to cover costs, and what is the difference in the increases between the current cost structure and the structure with benchmark performance-efficiency?
    - What is the scope for reducing costs and collection losses in the power sector in SSA, and how much will such cost and collection-loss reduction increase the financial viability of utilities in the region?
    - What sequence of policy measures could be considered in the short, medium and long term?

Policy makers, policy analysts, researchers, utilities, and other practitioners in the power sector in SSA are the primary audience of this work. It is also intended to provide insights to inform international financial institutions, including the World Bank, in their policy dialogue with governments in the region, and well as inform sector dialogue and project choices at a strategic level.

Cash collected by utilities might fail to cover operating expenditures (opex), let alone costs that should be incurred (for capacity maintenance, upgrade, and expansion). It is important to note there are several levels of financial viability, while the term is often used in a general sense without recognition of the different levels. Table 1 presents a simplified taxonomy, referencing the basic components of capital expenditure (capex) and opex. Increasing levels of financial viability move closer to costs based on commercial principles where utilities pay all applicable taxes and market-based interest rates, dedicate adequate resources to operations and maintenance, and earn commercially competitive returns on equity capital.

**Table 1: Utility financial viability ladder: a simplified taxonomy**

| Level of financial viability | Comment |
|---|---|
| Level 1: Not covering existing opex. | Financially unviable, loss-making utility. |
| Level 2: Utility covers at least existing opex. | Utility dependent on government for capital investments. |
| Level 3: Utility covers existing opex plus concessional financing costs on new replacement value of existing assets. | Utility dependent on access to concessional financing. |
| **Level 4: Utility covers existing opex and full capex on new replacement value of existing assets.** | **Base-case definition used in this study, using a 10-percent real discount rate for capex.** |
| Level 5: Utility covering efficient opex and full capex on new replacement value of existing and future assets. | Future assets based on a least-cost expansion plan. |
| Level 6: Utility covers efficient opex and full capex on new replacement value of existing and future assets plus environmental externalities. | Definition of financial viability that may be used in high-income economies. |

*Source*: World Bank staff.

Many utilities operate at level 1 where they depend on subsidies to operate, either through ongoing subsidies year to year, or through large lump sum bailout transfers and or debt rescheduling / forgiveness. Utilities operating at level 1 may also avoid costs, with maintenance costs often one of the first to be cut. The first step for most utilities in SSA therefore is to achieve cost recovery levels 2 or 3 as a minimum. However, recognizing substantial investments required to meet demand as well as reach universal access, and the extremely limited availability of concessional financing to meet investment needs, this study uses level 4 as the base-case level for QFD estimations.

# 2 Approach and Methodology

## 2.1 Approach

The study takes the dominant state-owned utility—the dominant state-owned distribution company if the utility is not vertically integrated—in each country and estimates QFDs under two cost scenarios, while maintaining the same average tariff levels:[3]

1. Current cost structure
2. Cost structure if operational efficiency is improved to limit aggregate T&D and collection losses to 10 percent and target staffing at benchmark levels.

There are five cases in SSA where the utility has a high level of private sector participation. In four cases, the reference utility is under a long-term concession with a private company (Cameroon, Côte d'Ivoire, Gabon, and Uganda). While the term "quasi-fiscal deficit" is not strictly accurate in these cases, the state still plays a significant or leading role in making investments in the power sector. The financial statements of the reference utilities are available in these cases and used in the analysis. In Nigeria, all distribution utilities have recently become majority-privately owned and utility financial statements are not yet available. A specific approach is taken for Nigeria, which is explained in section A1.5 in annex 1.

The factors responsible for the deficits are analyzed by calculating the components below:

Hidden costs = underpricing + T&D losses + under-collection of bills + overstaffing.[4]

Table 2 shows the distinction used in the AICD and in this paper between T&D and bill collection losses. These losses consist of technical and nontechnical losses. Technical losses are for electricity consumed by T&D lines and transformers (but not by customers) during transmission of electricity to consumer's premises, whereas non-technical losses are for electricity consumed by customers that is not billed due to actions external to the power system—such as theft, meter tampering, and deliberate under-reading of consumption—and under-recording of consumption due to lack of meter maintenance and calibration. Both forms of losses are disproportionately concentrated in the distribution segment, and represent losses that utilities cannot recover because the electricity "lost" has never been nor will it ever be billed to customers. It is important to note that unmetered customers can still be billed, which is the case in Nigeria. That is, not metering doesn't automatically translate to not billing the unmetered customer. Bill collection losses occur after the point of sale, and utilities can recover them in principle through debt collection mechanisms.

[3] This is a departure from the classic studies on QFDs, which defined benchmark performance to include cost-recovery tariffs, making QFDs zero by definition at benchmark performance.
[4] It is important to note this formula includes accrual and cash accounting items. Uncollected bills become receivables and eventually a loss only once recognized as uncollectable.

**Table 2: Typology of losses**

| | T&D losses (up to the point of sale) | Bill collection losses (after point of sale) |
|---|---|---|
| **Technical** | Technical losses including transmission losses, substation losses, under-billing due to inaccurate meters due to lack of maintenance, primary and secondary distribution losses | Not applicable |
| **Nontechnical** | Unmetered consumption due to theft, lack of meters, meter tampering, faulty meter reading | Under-collection of bills due to faulty bill distribution and inadequate systems to manage bill collections |

*Source*: World Bank staff.

For underpricing, benchmark tariffs are needed against which existing tariffs are compared. There is a large and rich literature on what would be efficient utility pricing. While setting prices at marginal costs is efficient, there are increasing returns to scale in the power sector, which could result in the average cost being higher than the marginal cost. Using a single price equal to the marginal cost could result in large financial losses for the utilities. Coase (1946) argued that multi-part pricing would provide efficient pricing under such circumstances, whereby additional units (of electricity) are purchased at the marginal cost, and the utility recovers full costs by levying a service charge in addition. When averaged over all consumers, the average tariff per kWh would equal the total unit cost. Applying these principles would require computing the cost of service based on a least-cost, long-term expansion plan. Such modeling for each country in SSA is beyond the scope of this study.

For simplicity, this study assumes that underpricing is the difference between revenues reflecting prudently and reasonably incurred expenses for efficient management of the power supply chain (but before optimizing the power generation mix and associated transmission infrastructure using least-cost, long-term, sector-wide planning) on the one hand and revenues currently charged (but not necessarily collected) on the other. This study, as the AICD, assumes that efficient operation would allow for total losses of 10 percent of total electricity dispatched to the grid before billing and zero under-collection of bills.[5] To compute underpricing on a unit basis—per kWh so billed—the computed average price needs to be compared with the volume-weighted average of the tariffs being charged. An accurate calculation of the volume received by each consumer category would be difficult if there are large commercial losses. The assumption about optimal staffing levels in this study is different from that in the AICD, as explained below.

## 2.2 Methodology in the present study

This study follows the same approach as that used in the AICD.[6] A quasi-fiscal deficit is the difference between the net revenue of an efficient utility ($R_{benchmark}$) and the net current revenue ($R_{current}$). Let capex designate benchmark capital expenditure, which is equivalent to current capex in this study. Let $opex_{benchmark}$ designate benchmark operating expenditure, and Q designate dispatched kWh. The tariff at benchmark performance, $tariff_{benchmark}$, in this study is (capex + $opex_{benchmark}$)/0.9Q and the revenue of an efficient utility is $tariff_{benchmark}$x0.9Q, where 0.9 accounts for combined transmission, distribution, and billing losses of 10 percent (level considered for benchmark performance). Its net revenue is $R_{benchmark}$ –

[5] In effect, this assumption is equivalent to a total combined revenue loss of 10 percent from T&D and bill collection losses. If T&D losses are smaller than 10 percent, bill collection efficiency can be lower than 100 percent as long as the combined loss is 10 percent.
[6] The methodology used in the AICD is described in section A1.1 in annex 1.

$cost_{benchmark} = R_{benchmark} – (capex + opex_{benchmark}) = 0$, signaling that the revenue of an efficient utility fully covers its cost. The revenue at current performance by contrast is $tariff_{current}$xQx(0.9 – TDL)x(1 – BL).

Using $\Delta$ to designate unit underpricing, $tariff_{benchmark} – tariff_{current}$, the quasi-fiscal deficit becomes

$$R_{benchmark} – (capex + opex_{benchmark}) – (R_{current} – capex – opex_{benchmark} – overstaffing) =$$
$$Overstaffing + tariff_{benchmark} x0.9Q – tariff_{current} xQx(0.9 – TDL)x(1 – BL) =$$
$$Overstaffing + tariff_{benchmark} \times 0.9Q – (tariff_{benchmark} – \Delta)xQx(0.9 – TDL)x(1 – BL).$$

The quasi-fiscal deficit can be decomposed into four hidden-cost components as

$$\underbrace{\Delta xQx(0.9 – TDL)x(1 – BL)}_{\text{Underpricing}} + \underbrace{tariff_{benchmark}xQL}_{\text{Transmission \& distribution losses}} + \underbrace{tariff_{benchmark}xQx(0.9 – L)xBL}_{\text{Bill collection losses}} + Overstaffing.$$

At benchmark performance, the last three terms are zero, leaving only underpricing.

In the above

- TDL is transmission and distribution losses in excess of 10 percent;
- BL is bill collection losses;
- capex represents new replacement values of existing assets and is annualized using a real discount rate of 10 percent, as in the AICD (see section A1.4 in annex 1 for more details);
- opex is the sum of $opex_{benchmark}$ and overstaffing cost; and
- overstaffing is the excess number of employees relative to the benchmark number of employees, as described in section A1.6 annex 1.

Opex, alternatively called operations and maintenance (O&M) costs, are those reported in utilities' financial statements inclusive of taxes and spending on power purchases, including power from independent power producers (IPPs), emergency power, and imports, but exclusive of rebated taxes such as value-added tax (VAT). For the purposes of estimating the cost overstaffing represents to utilities, this analysis assumes staff costs could be reduced by 50 percent of the overstaffing level. This reflects two parameters the utility can choose to adjust: salaries and staff numbers. At one end of the spectrum, the utility could reduce staff numbers to the optimum level and increase salaries to attract higher capacity staff, which would be cost neutral. At the other end of the spectrum, the utility could choose to reduce staff numbers to the optimum and keep salaries constant, which would reduce staff costs in proportion to the staff reductions. The assumption in this study considers a mix of these two approaches.

It is worth noting that financial accounting for large companies is on an accrual basis, and as a result revenue is not cash collected but totals the amounts billed. For the remainder of this paper, revenue (amounts billed) is the amount before collection losses are factored in. By contrast, cash collected is on a cash basis and captures collection losses. Because revenue is on an accrual basis and cash collected is on a cash basis, they are usually not equal even if the bill collection rate is 100 percent.

Because capex and opex are not derived on a common basis, estimating the unit cost under benchmark performance used in the calculation of underpricing requires using different denominators:

$$Unit\ cost = \frac{(\Sigma\ Overnight\ investment\ costs\ for\ power\ generation\ and\ HV{+}MV\ lines\ annualized) + US\$100 \times no.of\ new\ customers}{kWh\ dispatched \times (100\% - 10\%)} + \frac{US\$0.023}{kWh} \times \%\ urban\ share + \frac{US\$0.042}{kWh} \times \%\ rural\ share + \frac{reported\ annual\ operating\ costs}{kWh\ billed},$$

where

- HV is high voltage and MV is medium voltage;
- US$0.025 and US$0.05/kWh represent the costs of low-voltage (LV) distribution lines (below 1 kV) in urban and rural areas, respectively, detailed in section A1.4 annex 1;
- new customers are customers added in the previous year; and
- US$100 represents the cost of a new meter and installing a line from the grid to the customer's premises.

The first term for capex is divided by 90 percent of kWh dispatched (allowing for 10 percent T&D losses) and the second term is to account for capex for LV distribution lines based on regulatory costs in Peru (which allow for total losses of 10 percent comprising T&D and collection losses), but opex does not correspond to operational efficiency of 10-percent total losses or proper maintenance of existing assets.

## 2.3 Data sources and coverage

A database was developed to capture more than 300 indicators related to the financial, commercial, and technical aspects of power sectors in SSA. The primary sources of data were utility financial statements and annual reports. Where data gaps remained, data were collected directly from utilities, or taken from available reference documents, including cost-of-service studies, tariff studies, power sector reports, industry sources, regulatory documents, and project documents, supplemented by locally available data provided by World Bank specialists working in the sector. Where data were inconsistent between sources, priority was generally given to utility data over other sources.

**Countries in scope.** Data availability determines the countries in scope in each analysis presented in this paper. The 39 countries included in this study out of 48 in SSA accounted for 95 percent of installed capacity, 86 percent of the population, and 85 percent of GDP in SSA in 2014. Due to lack of data, the following nine countries were excluded from the analysis: Angola, Chad, the Democratic Republic of Congo, Equatorial Guinea, Eritrea, Guinea Bissau, Namibia, Somalia, and South Sudan.

**Reference utility and sector structure.** The general methodology used in this paper estimated opex using the financial statement of the main utility listed in annex 2, and estimated capex costs of existing state-owned assets using a new replacement value approach on assets reported in utility annual reports. This methodology means that the sector structure has a significant effect on the computation of capex and opex.

Figure 1 summarizes the sector structures observed in SSA. For each country analyzed in this paper, the structure shown in the figure is that in the reference year. For those excluded from the study, the structures shown are based on the most recent available data. The procedures and assumptions applied to take account of sector structure are outlined in section A1.5 in annex1. The structures are categorized into five groups:

- **Group 1: One vertically integrated state-owned utility**. In 19 countries the sector was fully vertically integrated, with one state-owned utility operating as a monopoly. Most of the countries excluded in the study due to lack of data fall into this group. Of the 19, seven lacked data for inclusion in the present study, leaving 12 included in the study.

- **Group 2: One vertically integrated utility with one or more generation companies.** Several sub-groups are identified in Figure 1. One has a state-owned vertically integrated utility and a separate state-owned generation company. A second sub-group has one state-owned utility, which is the main utility, and some private generation companies, such as IPPs and emergency power producers (EPPs). A third sub-group has private generation companies and one vertically integrated utility that is under a long-term private concession (with investment responsibility, or without investment responsibility, such as in Gabon; the latter is sometimes referred to as an *affermage*).
- **Group 3: One main vertically integrated utility with other operators.** Many of the countries in this group are in Southern African. In most cases, the main state-owned utility sells electricity to other utilities performing distribution activities to end-users, including exports. One example is South Africa where Eskom sells to municipalities. Of the seven countries in group 3, five are included in this study, with Angola and Namibia excluded for lacking sufficient data.
- **Group 4: Partial vertical unbundling with and without other operations**. Three countries have some form of vertical unbundling with one operator managing T&D, and others managing generations activities. In Zimbabwe, these companies are under one holding company with separate operations and accounts. All are included in the study.
- **Group 5: Vertical unbundling with and without horizontal unbundling in distribution**. Four countries in SSA have vertical and horizontal unbundling and are the most advanced market structures in SSA, but do not have competitive markets. Nigeria underwent a major privatization process in 2014 as part of a major power sector reform process. Private ownership is 60 percent for distribution companies and, with one exception, at least 80 percent for generation companies. In Uganda, Umeme has a concession on distribution, and Eskom has a concession on some hydropower assets in addition to IPPs. All four are included in the study.

**Data from utility financial statements**. This study takes revenues and opex from utility financial statements. The study assumes that accounting is performed on an accrual basis, in accordance with the International Financial Reporting Standards (IFRS) and International Accounting Standards (IAS).

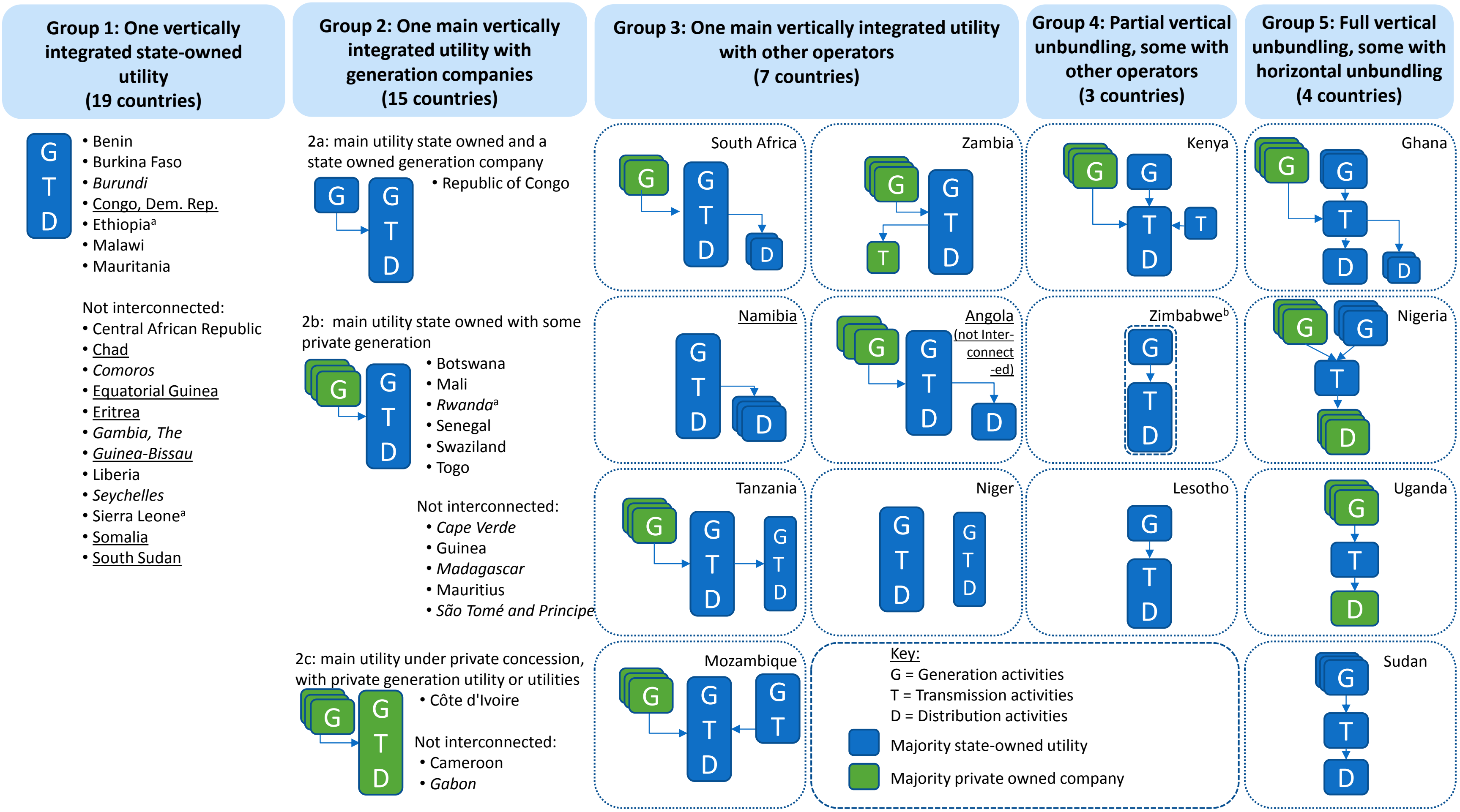
- **Revenues** captured in the analysis concern only those directly related to electricity sales that are retained by power utilities. As mentioned earlier, reported revenues therefore reflect the amounts billed and not amounts collected. Subsidies in the form of direct transfers from the government or international donors are excluded. Revenues not directly related to sale of electricity are excluded, such as those earned from sale of water for the utilities that provide both services.
- **Operational expenditures** captured include all fixed and variable O&M costs, and taxes that are not rebated such as corporate income tax. All costs deemed to be related to capital costs are excluded because they are replaced by calculated annualized capex for existing assets. All loan repayments—interest payments typically recorded on income statements and principal payments typically recorded on cash-flow statements—are considered to be for capex. Other exclusions include depreciation, losses on foreign denominated debt, costs not directly related to electricity sales (such as costs of providing water services), and costs from extraordinary activities.
- **Utility financial statements** differ in quality and availability, as described in annex 1.2. Of the 39 reference utilities, 23 had their statements audited, 13 by international accounting firms and the

remaining ten by local accounting firms. 16 make their annual reports, financial statements, or both available publicly online.

**Reference year of analysis**. Analysis was carried out for a specific reference year. The year used was the most recent year with a full set of critical data available: financial statements, electricity sales, and power mix on installed capacity. In a small number of cases the study needed to make assumptions to fill non-critical data gaps through interpolation or other means.

Utilities report by fiscal year. If a fiscal year covers 12 months straddling two calendar years, the reference year is designated by the calendar year with a larger share of months in the fiscal year. If there are six months in two successive calendar years, the second of the fiscal year is taken as the reference year. Therefore, the reference year for fiscal year July 2011–June 2012 is 2012, but the reference year for fiscal year April 2011–March 2012 is 2011. With the exception of Lesotho (2010), and Kenya (2015), the reference year for most countries is between 2012 and 2014 (Table 3). The majority of countries (22) have a reference year of 2014. A breakdown by country is provided in annex 2.

**Figure 1: Electricity sector structures in Sub-Saharan Africa**




*Source*: World Bank staff illustration.

*Note:* Countries underlined are excluded in the main analysis presented in this paper due to lack of data. *Utilities of countries in italics* provide other services such as water and sewerage. Countries are interconnected with one or more other countries unless otherwise indicated. Interconnection refers to HV infrastructure to facilitate power imports and exports, and excludes MV and LV cross-border sales to local communities on the border. The study excludes 75 state-owned generation companies operating a small fleet (less than 15 megawatts) that typically serve isolated rural electrification systems or specific government entities, and distribution companies that account for less than 5 percent of end-user sales, both grid-connected (e.g. Senegal, Uganda, Zambia) and off-grid.

a. Sectors in Ethiopia, Rwanda and Sierra Leone have undergone sector reform subsequent to the reference year, and sector structures have evolved from those illustrated.

b. The dotted line represents the parent company that owns the two companies in the sector.

**Table 3: Summary of reference year for analysis**

| Reference year | Number of countries |
|---|---|
| 2010 | 1 |
| 2011 | 0 |
| 2012 | 6 |
| 2013 | 9 |
| 2014 | 22 |
| 2015 | 1 |
| **Total** | **39** |

*Source*: World Bank staff.

**Conversion to 2014 U.S. dollars.** The majority of reference documents report finances in local currency units. To minimize distortions caused by major exchange rate fluctuations between the reference year and calendar year 2014, this study reports many results in current U.S. dollars rather than in constant U.S. dollars. To compute the regional average for QFDs as the percentage of regional GDP, percentages in the 39 study countries in the reference years are weighted by their GDP weights in 2014. For cross-country comparison of costs and revenues expressed on a per-kWh basis, the study converts reported values (with the exception of capex) to 2014 local currency units using local consumer price indices, and then to 2014 U.S. dollars by applying the official exchange rate in 2014. An analysis based on nominal values with specific inflation assumptions for each cost component is beyond the scope of this analysis. Capex is not adjusted, because it is based on generic plant cost per kW in U.S. dollars obtained from different sources (see Table A1.2 in annex 1), the applicable years of which are not precisely defined.

**Fuel costs**. Diesel and heavy fuel oil (HFO) costs comprise a significant portion of opex in many countries. Where input fuel costs are subsidized, the full costs are not captured on the utility financial statements. Unfortunately, only ten countries—Cameroon, The Gambia, Kenya, Liberia, Mauritania, Mauritius, Niger, Rwanda, the Seychelles, Sierra Leone—reported fuel costs separately. At least three SSA countries are known to subsidize the cost of fuel directly:

- **Angola**. The price of diesel for electricity generation, which accounts for about one quarter of total diesel fuel consumption, is zero (IMF 2015a). Angola, however, is not among the study countries.
- **Côte d'Ivoire**. The government provides subsidized fuel for electricity generation through two channels. One is free gas based on the government's 15-percent equity share in domestic gas fields. The other is subsidized heavy vacuum oil provided by the oil refinery to the utility. Gas and oil subsidies for electricity generation in 2013 were estimated to be US$131 million, or US$0.03 per kWh billed (World Bank staff estimates). In 2014, the subsidy for heavy vacuum oil exceeded the initially budgeted amount by two-thirds and totaled US$100 million. The government is reportedly focusing on investing US$9 billion to revamp and expand the power infrastructure, which will eliminate the need for heavy vacuum oil (IMF 2015b).
- **Madagascar, Niger, and São Tomé and Príncipe** provide sales tax exemption or exemption from fuel import duties.

In other countries, natural gas prices are capped at artificially low prices by the government, combined with a domestic supply obligation, as in Nigeria. While this may not entail budgetary transfers to gas producers, these low prices have discouraged gas development and production, leading to gas shortages, which in turn have exacerbated power shortages. Beyond known cases such as Côte d'Ivoire, estimating underpricing of natural gas, however, is considered outside the scope of this study.

## 2.4 Limitations due to approach and data gaps

While following the basic framework employed in the AICD with some modifications for improvement, the approach in this study has a number of limitations for the benchmark cost of service, which is needed to estimate underpricing:

- The procedure does not calculate the cost of service based on the least-cost expansion plan. Estimates of supply costs are limited to existing assets, and future capacity expansion, which can be considerable, is not considered. The computed average unit capex cost for power generation in this study and in the AICD ("historical cost") would be comparable to the unit cost that should have been calculated if the power mix remains broadly the same in the least-cost expansion plan. An increasing shift away from oil to other forms of power generation, addition of substantial non-hydropower renewable energy (which is largely missing from the present analysis, which is based on the existing assets as of mostly 2013 and 2014), and any other marked changes in the power mix could make the calculations depart measurably from that for the least-cost expansion plan.
- Hidden-cost analysis is subject to the typical limitations of top-down benchmarking analysis, which relies on comparing reported values against reference values. Estimating benchmark performance for each utility is beyond the scope of this regional study. This one-size-fits-all approach has obvious limitations and cannot substitute for a detailed utility-specific analysis. Efforts were made in this study to break down benchmarking of staffing into generation, transmission, and distribution, but vastly simplifying assumptions had to be made about capex. Further limitations of the overstaffing analysis are described in section A1.6 in annex 1.
- While capex is calculated, opex is taken from utility financial statements, except for the addition to reported opex of the calculated fuel price subsidy in Côte d'Ivoire, discussed in section 2.3. Opex should be based on benchmark performance in the least-cost expansion plan, but is not and is different from that under optimal performance. On the one hand, often less than optimal opex is actually spent on maintenance and repair due to cash flow and other financial limitations (see the next bullet). On the other hand, unit opex may be markedly higher if sub-optimal planning leads to greater reliance on diesel-powered generation and other expensive forms of coping.
- Expenditures not incurred by the utility are almost never reported in financial statements. Utilities facing financial difficulties—which is the case with most in SSA—have been known to cut costs by not carrying out necessary maintenance and other services. Underspending on maintenance and refurbishment is virtually impossible to capture by studying utility financial statements and annual reports, yet years of underspending on maintenance could lead to the need for a large bailout from the state at some point. South Africa's recent power outages, for example, have been exacerbated by breakdowns and declining availability of Eskom's power generation capacity. Quantification of poor maintenance, a chronic problem in SSA, is not possible without doing much more detailed analysis, which is beyond the scope of this study. Tax expenditures (tax reductions or waivers) are almost certain not to be reported. Where there are budgetary transfers to the utility, such transfers may be reported in financial statements. But if transfers go to other parties—such as the government's paying for emergency power rentals or paying fuel suppliers directly—such input subsidies are usually not reported.

- As with capex, unit opex derived in this way would be a reasonable approximation if the energy mix remains approximately the same as that in the least-cost expansion plan, provided that all necessary expenses are incurred and reported in utilities' financial statements. But a significant change in fuel composition for power generation (such as a large shift away from oil-based generation) could affect the results markedly.
- For a fixed set of existing assets, unit costs (costs per kWh) increase with decreasing utilization rate. In many plants, utilization rates are low because years of inadequate maintenance have led to frequent mechanical breakdowns, if not rendering items of equipment unusable. In some countries, utilization rates are low for lack of fuel, as with natural gas shortages in Ghana and Nigeria. Increasing kWh dispatched by increasing utilization rates may reduce underpricing in these circumstances.
- Additional simplifications for capex and T&D losses increase calculation uncertainties. US$100 for each new connection in the above equation is an order-of-magnitude estimation not specific to a given market. The basis for valuing T&D losses is the unit revenue derived from multiplying total revenue by losses in excess of 10 percent, but such a simplifying approach ignores fixed charges that are collected irrespective of T&D losses.
- Because capex is based on new replacement values of existing commissioned assets, capex for new infrastructure is included only when the infrastructure is commissioned—expenditures being incurred in earlier years for building the infrastructure are not counted. Tariffs may not be raised to match the annualized cost of the new infrastructure, and in the first year of operation, a generation plant may not operate at full capacity, further widening the gap between cost and revenue.
- Snap-shot calculations for the reference year by definition do not capture significant variation in opex from year to year. The largest contributing factor to such variation is spending on fuel purchase, which in turn depends on rainfall (in countries reliant on hydropower) and other factors. Outages of non-oil power generation—due to droughts (as in Zambia and Zimbabwe in recent years), gas shortages (as in Ghana in recent years), and other causes—and power shortages more generally can increase fuel bills markedly by requiring oil-based generation, such as (emergency) diesel power generation. Conversely, plentiful rainfalls or elimination of emergency power rentals can slash fuel (and rental) bills. The possibility of marked variation in opex from one year to the next was investigated as part of the multiyear analysis presented in section 8.
- The AICD found that the historical average cost of power supply—relying on small and inefficient technologies—was higher than the incremental cost of new power supply in the future.[7] This observation might argue for costs being lower under optimal planning, although the approach followed here and in the AICD did not take economies of scale in power generation into account in calculating capex (with the exception of hydropower generation), so that the extent of overestimation of costs may be limited.
- Financial statements are also unlikely to indicate missed loan repayments—which could eventually result in debt forgiveness, as in South Africa in 2015, and below-market provisions of loans and loan guarantees. However, loan repayments are not used in this study, replaced instead by calculated capex, and missed loan repayments affect only vertically unbundled sectors with power purchases from upstream state-owned utilities (see below).

[7] That said, as explained above for the case of increasing returns to scale, the average tariff cannot be equated with the unit incremental (marginal) cost.

There are additional important limitations due mainly to lack of data availability:

- Audited utility financial statements may not be available or may be incomplete. As noted above, only unaudited financial statements may be available—making inaccuracies more likely—or utility financial statements may be partial. No financial statements were available for Nigeria and an alternative approach was used, as explained in section A1.5 of annex 1.
- The levels of detail provided in utility annual report and financial statements varies significantly. Some utilities provide a detailed breakdown of costs, such as the cost of power purchases from each supplier, but others (such as Société Nationale d'Électricité in the Republic of Congo) lump all generation costs, including power purchases and self-generation, into one line item. Where the utility provides multiple services, some, such as NAWEC (Gambian utility providing electricity, water, and, sewage services) do not break down costs by product due to limitations in internal accounting systems. Annex 2 explains how these cases are handled.
- Overnight investment costs assume a single number for each technology, irrespective of scale or location, with the exception of hydropower generation. The effects of location and economies of scale are substantial. For example, while this paper assumes US$1,070 per kilowatt (kW) for diesel generation, a 2014 report on the least-cost power development plan in Liberia uses US$1,550/kW for a diesel generation unit of 1 megawatt (MW), declining with unit size to US$900 for a unit of 20 MW. Similarly this study uses three costs for T&D capex—one for lines down to 110 kV, another for lines below 110kV down to 66kV, and another for distribution lines below 66 kV down to 1 kV—which are the same everywhere. Because reliable information on the distance covered by LV distribution lines (below 1 kV) is not available in any country, the costs of constructing such infrastructure were estimated by using costs allowed by the regulator for revenue in Peru, with rural costs being almost twice those in urban areas.
- Where the sector is vertically unbundled, isolating opex through the supply chain becomes more challenging. If power is purchased from state-owned generation or transmission utilities, this analysis subtracts loan repayments made by these upstream utilities from the purchase costs paid by the reference utility to arrive at opex, on the assumption that loan repayments are for capex and capex is calculated as new replacement values of existing assets. This calculation procedure introduces the possibility of two errors:
    1. Financial statements for all state-owned companies may not be available or may be incomplete, as in the Republic of Congo, and Ghana. In these countries, the power purchase costs were assigned entirely to opex. Such an approach would overestimate capex if the power purchase costs had included capex cost-recovery elements. As explained in section A1.5 in annex 1, to avoid double counting, this study assumes that power purchases from the state-owned companies with missing information were fully cost-reflective, and the calculated capex estimates exclude the installed capacity of the companies with missing information, which may lead to underestimation of costs.
    2. Even where financial statements are available, for power purchased in an unbundled sector from another state-owned utility, isolating the capex component is difficult. Loans for the power sector (or any other sector) in SSA do not have tenor anywhere near the economic life assumed in this study, unless the loans are highly concessional and from a donor. For infrastructure with no loan repayments, depreciation values may correspond more closely to the new replacement values calculated in this analysis. But there is not enough information in financial statements to indicate the breakdown of loan repayments and depreciation by generation plant and T&D infrastructure. Further, not all loan repayments

may be for capex. Serious revenue shortfalls may have forced some utilities to borrow to cover short-term needs unrelated to capex, but there was no information on what the loan repayments were for.

- For sales to other utilities performing distribution activities, this study treats all sales of the main reference utility as end-user sales. However, in the case of horizontal unbundling in distribution, the main reference utility may sell to other utilities performing distribution activities to end-users. The most significant example is South Africa, where Eskom sells to dozens of municipalities, which in turn account for 40 percent of sales to end-users. This introduces scope for potential errors. If other distribution companies have higher tariffs and or lower T&D and collection losses, the QFD may be overestimated. Conversely, if other distribution companies have lower tariffs and or higher T&D and collection losses, or there are subsidies provided directly to those utilities, the QFD may be underestimated. In all cases, the main reference utility represents the vast majority of end-user sales, limiting the size of this potential error.
- Bill collection rates reported by utilities are not part of IFRS and are therefore unaudited. They are assumed to represent the cash collected in a given year as a proportion of revenue billed. Cash collected in any given year will include cash collected on arrears from bills issued in previous years. The breakdown of cash collected in the reference year versus arrears is typically not provided by utilities. If the proportion of payment for arrears from previous years does not change significantly from one year to the next, this uncertainty is not expected to make significant differences.

# 3 Characteristics of Electricity Sectors in Sub-Saharan Africa

This section presents aggregate data on the characteristics of electricity sectors in the 48 countries of SSA unless otherwise noted. Detailed country-level data on the characteristics of electricity sectors in the countries studied in this paper can be found in annexes 2-7. Additional electricity sector characteristics related to operational efficiencies are discussed in section 0. Apart from the access data based on the Global Tracking Framework of the Sustainable Energy for All initiative (SE4ALL) and installed capacity data, all other data are for the reference year for the 39 countries covered in this study and for the most recent year for which data are available for the countries excluded from the study. As such, regional averages presented in this section do not represent averages of data in the same year but the data are from different reference years (except for installed capacity for which data was available for a common reference year).

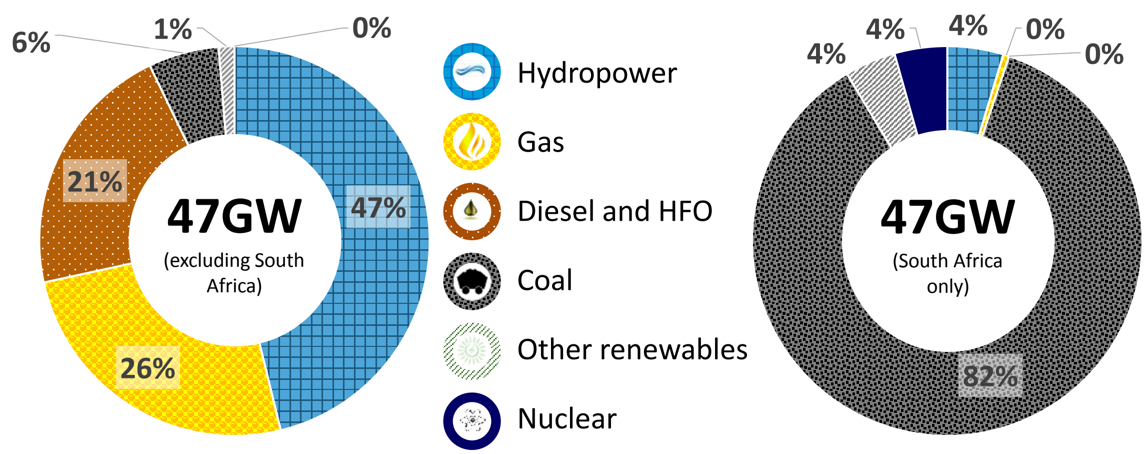
## 3.1 Access

The regional access rate of 35 percent is less than half percent of the global average levels of access of 85 percent (SE4ALL 2015a). Mauritius and the Seychelles have 100 percent access to electricity, followed by Gabon (89 percent) and South Africa (85 percent). A further nine countries have access rates above 50 percent. Rural areas remain the most underserved in the world. In some countries, less than 5 percent of rural population has access to electricity.

## 3.2 Installed capacity and power mix

Installed capacity in Figure 2 consists of all domestic grid-connected capacity, including IPPs, grid-connected power supply for exports and industry, and emergency power. It excludes enclave-generation such as mines. To avoid double counting, country-specific estimates exclude capacity from imports.

**Figure 2: Power mix on installed capacity, 2014, percent of total**




*Source*: World Bank staff calculations taking data from utility annual reports and other documents.

With a population of almost one billion people, installed capacity in all 48 countries in SSA in 2014 was 94 gigawatts (GW), up from 68 GW in 2005 (Eberhard et al 2011). The total regional capacity is less than that in Spain, whereas Spain has a total population of 50 million, against 962 million in SSA. South Africa with 47 GW accounted for half the capacity in SSA. Fourteen countries had power systems larger than 1

GW and accounted for 90 percent of power capacity in SSA. Nigeria, with more than three times South Africa's population, had only 23 percent of its installed grid generation capacity. Eighteen countries had systems smaller than 150 MW. Installed capacity in SSA was 99 MW per million population in 2014, compared to 194 MW in India (CEA 2015), 437 MW in Mexico, and 894 MW in Poland in 2013 (IEA 2015).

Figure 2 shows that, excluding South Africa, hydropower has the largest share (47 percent), followed by gas (26 percent), liquid fuels (diesel and HFO 21 percent), and coal (6 percent). Other renewable energy sources—such as biomass, geothermal, wind, and solar—account for only 1 percent. The vast majority of the continent's hydropower potential remains undeveloped, with much of that potential located in the Democratic Republic of Congo, Ethiopia, and Cameroon. Most of the thermal-based power depends on imported fuel, with only a few countries (such as South Africa, Nigeria, and Côte d'Ivoire) using domestic resources. South Africa is heavily dependent on coal, with 82 percent of its 47 GW installed capacity being based on coal. Annex 3 provides more detail.

## 3.3 Power purchases

Power purchases refer to purchases from IPPs, EPPs, and imports, including regional special-purpose vehicles (SPVs) which are jointly owned by two or more countries and provide generation, transmission, or both. Data are available for 40 countries (see annex 5). The majority of power in SSA is generated by state-owned and operated utility companies. Approximately 29 percent of power dispatched onto national grids is power purchased from majority-private producers (18 percent) and through imports (11 percent). Purchases from private producers include those from public-private partnerships and sales of excess power from captive power plants at mines and factories. Public-private partnerships include IPPs with traditional long-term power purchase agreements; EPPs, which are playing an increasingly important role on the continent; and concessions on state-owned generation assets such as Eskom in Uganda. On the basis of energy supplied, approximately one-half of IPP purchases are gas-based (dominated by Côte d'Ivoire and Tanzania), 20 percent is from liquid fuels, 15 percent from hydro, and the remainder is from other sources such as geothermal and coal.

The increasing use of grid-connected emergency power rental reflects the gravity of electricity challenges in SSA. Countries experiencing power shortages can enter into short-term rental contracts with specialized firms, which offer the service of quickly installed (within a few weeks) and reliable electricity. A 2011 report noted that there was at least 2 GW of known installed capacity in SSA from emergency power rentals, up from an estimated 750 MW in 2007 (Eberhard 2011). Emergency power rentals account for 30 percent of IPP purchases. Côte d'Ivoire's short-term contracts with Aggreko and Ciprel stand out as examples of large emergency power contracts on the continent: short-term rentals of 100 MW with Aggreko in July 2013 and 110 MW in CIPREL in January 2014 generating a combined 4,565 GWh of power in 2014. Emergency power rentals are relatively expensive. Typically containerized units run on diesel or HFO, with tariffs in the range US$0.30–0.40 per kWh during the reference years in this study. Côte d'Ivoire's emergency rentals are an exception because they run on gas.

Power trade in SSA remains limited. There is significant scope in exporting countries to increase the generation capacity of capital-intensive, low-unit-cost electricity resources such as hydropower, and in importing countries to benefit from such low-cost electricity. There are 19 net importers and 8 net exporters of electricity. Other countries have no trade. A portion of power purchases are through regional SPVs including OMVS (Organisation pour la Mise en Valeur du fleuve Sénégal) purchased by Mali, Mauritania and Senegal; Ruzizi purchased by Burundi, the Democratic Republic of Congo, and Rwanda; MOTRACO (Mozambique Transmission Company) purchased by South Africa, Swaziland, and Mozambique; CEB (Communauté Electrique du Bénin) purchased by Benin and Togo; and a small portion through the day-ahead market facilitated by the Southern African Power Pool.

## 3.4 Availability factors and reserve margins

Inadequate electricity is mostly the result of inadequate investment in new power generation capacity, but can also be the result of deteriorating performance of existing generation plants. One of the casualties of insufficient revenue is maintenance expenditure. Utility managers often have to choose between paying salaries, buying fuel, or purchasing spares (forcing them to cannibalize parts from functional equipment). The weighted average available capacity—which is lower than the nominal capacity due to age as well as mechanical and other constraints—for a subset of 20 countries with available data is 87 percent of installed capacity, falling to 73 percent if South Africa is excluded.

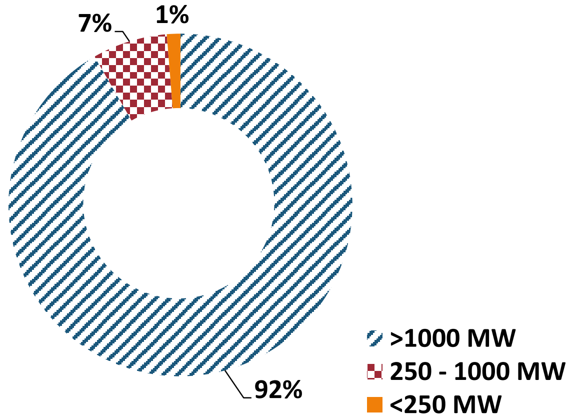
Reserve margins—available capacity over and above the capacity needed to meet normal peak demand—are small in many countries. Data are available for a subset of 14 countries, with a weighted average reserve margin of 18 percent, which is within the ideal reserve margin of 15–20 percent. However, utility reported estimates for peak demand are likely underestimated, because it is difficult to estimate unserved demand with customers not yet connected to the grid. In addition, there is a positive selection bias built into this estimate, as those utilities reporting available capacity and peak demand tend to be those better managed with the systems in place to track these data. Ethiopia, Kenya, Liberia, Mauritius, Senegal, and South Africa are the only countries with a reserve margin greater than 15 percent. Namibia and Zimbabwe have supply shortages in excess of 20 percent of peak demand.

## 3.5 Consumption

Consumption data are available for 46 countries. Average annual consumption in SSA, as measured by the amount billed by the utilities in the respective reference years and totaled across the countries studied, was 375 kWh per capita, falling to 153 kWh per capita if South Africa is excluded (see annex 6 for more detail). Although this measure does not capture self-generation or unbilled electricity consumption—which could be considerable—this is low by any international standards, even when compared to other emerging markets. For example, India had average consumption of 780 kWh per capita in 2011 (Pargal and Banerjee 2014) and Mexico averaged 1,952 kWh per capita in 2012 (IEA 2015). Within SSA, there is significantly higher consumption per capita in Southern Africa—pulled up by South Africa—than elsewhere. Annual consumption in South Africa was 4,000 kWh per person. Even after excluding South Africa, annual consumption in the rest of Southern Africa was 428 kWh per person, compared to only 111 kWh per person in Eastern Africa, the lowest consuming region in SSA. Annual consumption per connected customer is significantly higher, at 3,875 kWh per capita excluding South Africa, with the difference reflecting the low levels of access in SSA.

Fourteen countries have systems larger than 1 GW. Together, these larger systems accounted for more than 90 percent of electricity consumption in SSA, whereas 20 countries with systems smaller than 150 MW accounted for just over 1 percent (Figure 3).

**Figure 3: Percentage of GWh consumed by system size**




*Sources*: Utility annual reports and other documents.

| < 150 MW | 150–1000 MW | > 1000 MW |
|---|---|---|
| Burundi | Benin | Angola[a] |
| Cape Verde | Botswana | Cameroon |
| Central African Republic | Burkina Faso | Congo, Dem. Rep.[a] |
| Chad[a] | Congo, Rep. | Côte d'Ivoire |
| Comoros | Gabon | Ethiopia |
| Equatorial Guinea[a] | Guinea | Ghana |
| Eritrea[a] | Madagascar | Kenya |
| Gambia, The | Malawi | Mozambique |
| Guinea-Bissau[a] | Mali | Nigeria |
| Lesotho | Mauritania | South Africa |
| Liberia | Mauritius | Sudan |
| Niger | Namibia[a] | Tanzania |
| Rwanda | Senegal | Zambia |
| São Tomé and Príncipe | Togo | Zimbabwe |
| Seychelles | Uganda | |
| Sierra Leone | | |
| Somalia[a] | | |
| South Sudan[a] | | |
| Swaziland | | |

a. Country not included in this study.

For the 34 countries for which data on the breakdown of consumption by consumer category were available, residential consumers were the largest group, accounting for 41 percent of sales. The second largest consumer category was industry, including mining companies (excluding captive power generation not connected to the grid), accounting for 30 percent of sales and in some countries more than half of sales, such as 57 percent in Kenya in 2015. This was followed by commercial users (21 percent), exported electricity (4 percent), government and agriculture (1 percent each), and the rest of consumers making up the remaining 1 percent.

## 3.6 Quality of service

In addition to the low levels of access discussed in section 1, quality of service for those connected is a critical factor. In the context of financially strained utilities, spending on operations and maintenance is often one of the first line items to be cut, reducing the quality of service.

Quality-of-service data are available for 16 countries. However, data were reported in an inconsistent manner. Only four utilities reported data according to the international standards of system average interruption duration index (SAIDI), the annual average outage duration for each customer served, and system average interruption frequency index (SAIFI), the average number of interruptions that a customer would experience in a year. These four are shown in Table 4. These statistics are not necessarily comparable across countries, because it is not clear if the measurements and methodologies are the same.

**Table 4: Available SAIDI and SAIFI data**

| | SAIDI | SAIFI |
|---|---|---|
| **Cameroon** | 105 | 25 |
| **Liberia** | 35 | 212 |
| **Mozambique** | Transmission 59, distribution 1.25 | Transmission 52, distribution 1.25 |
| **South Africa** | 36 | 20 |

*Source*: Utility data.

Annex 7 shows the available statistics for the 16 countries. Most utilities do not have the systems in place to measure SAIDI and SAIFI accurately and provide some other data related to the duration of blackouts (for example, average outage duration of 40 hours in Côte d'Ivoire), or provide data at the HV and MV levels rather than at the LV level (such as Mali reporting 70 interruptions per year at the HV level and 224 interruptions at the MV level).

The substantial problems with the quality of service suggested by these data are consistent with indicative enterprise data available from the World Bank's Enterprise Surveys in 41 countries in SSA (World Bank 2016b). The data years for the Enterprise Surveys vary from country to country, nor do they necessarily match the reference years in this paper, but the medians are 6.3 outages per month (equivalent to 76 outages per year) and 5.5 hours per outage for those reporting outages.

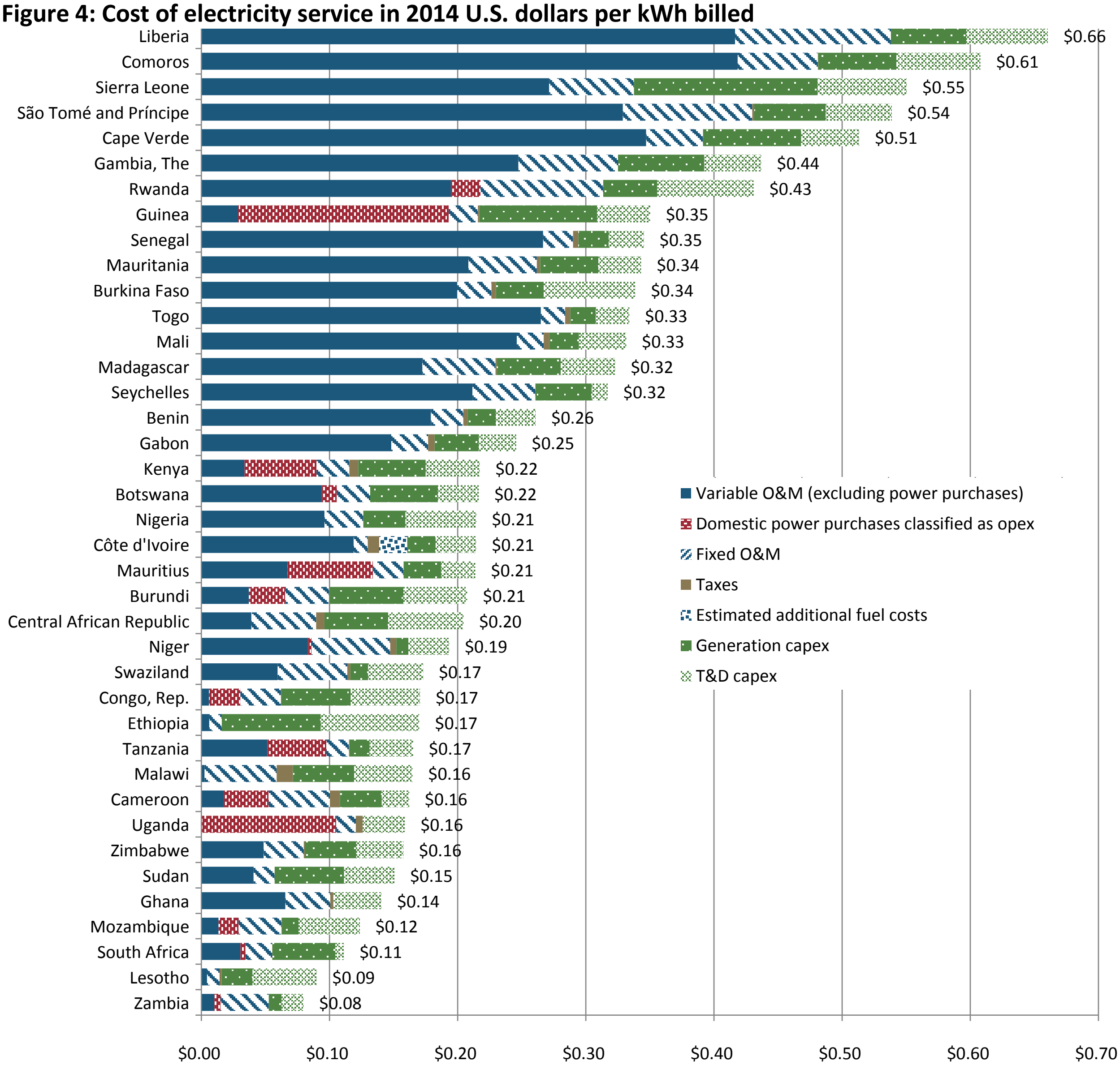
# 4 Current cost of service, tariffs, and revenue

This section presents analysis of costs and revenues on a subset of 39 countries in SSA for which critical data are available. For cross-country comparison, data presented in U.S. dollar are expressed in constant 2014 U.S. dollars, as explained in section 2.3.

## 4.1 Current cost of electricity service

Figure 4 shows the breakdown by country of costs of service calculated in accordance with the methodology described in section 2 and divided by kWh billed. Total unit costs range from as low as US$0.08 per kWh in Zambia to more than US$0.60 per kWh in Liberia and Comoros. The weighted average and median cost of electricity in SSA are US$0.14 and 0.21 per kWh billed, respectively.

**Figure 4: Cost of electricity service in 2014 U.S. dollars per kWh billed**




*Sources*: World Bank staff calculations based on utility financial statements.

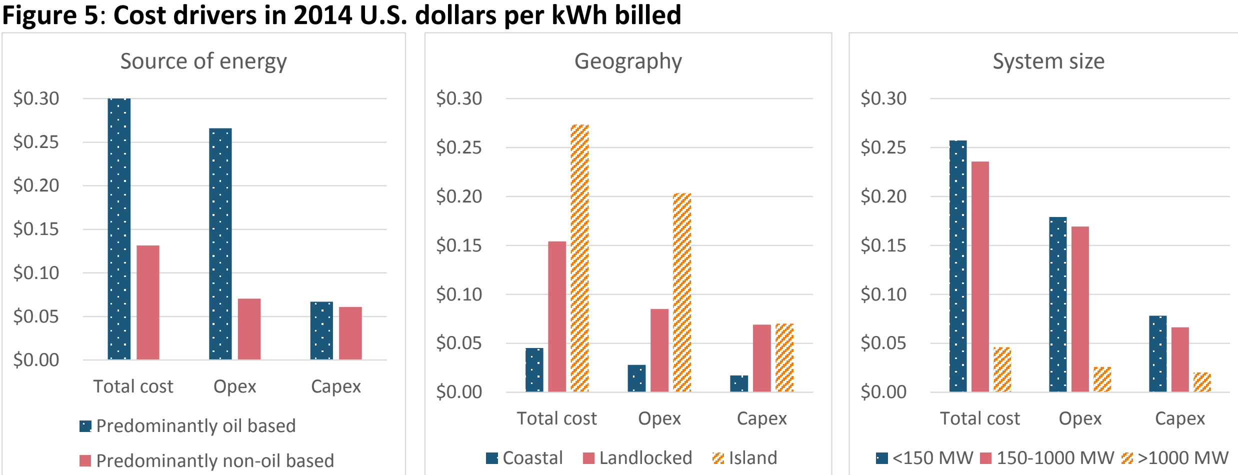
*Note:* Power purchases classified as opex = purchases from private suppliers and state-owned utilities with no financial statements; taxes = corporate income tax and other taxes not rebated to the utility; estimated additional fuel cost = fuel costs not recorded in utility financial statements.

Very high capex costs in Sierra Leone ($0.21 per kWh billed) are driven by the reliance on capital-intensive hydropower (Bambuna) which is operating at a relatively low capacity-factor (26 percent in the reference year) and very high T&D losses of 39 percent. Very high capex costs in Ethiopia ($0.15 per kWh billed) are driven by more than 1,400 MW of hydropower installed since 2000, and associated 9,000 km of HV transmission lines to evacuate the power. The majority of these investments were financed through the state and with debt servicing not being the responsibility of the utility (see section 5.1 for further discussion of the case of Ethiopia). The high capex costs in Ethiopia are consistent with earlier findings in the AICD. Similarly, relatively high capex costs in Kenya (US$0.09/kWh) are driven by 1,400 MW of hydropower and geothermal combined (out of a total 2,300 MW of installed capacity), with both technologies being heavily capital-intensive.

As explained above, the distinction between capex and opex is an artifact of the methodology selected in this study in countries where a sizable fraction of electricity is purchased from imports, private producers, or both, or where upstream state-owned utility has not issued financial statements. In all these cases, the entire purchase is classified as opex. These purchases represent more than 40 percent of total costs in two countries: Guinea with power purchases from an EPP, and Uganda with a concession and an IPP (Eskom has a concession on one of the generation companies, and Bujagali is an IPP).

There are several important divers for electricity costs (Figure 5). As expected, the 14 countries that depend on oil-based generation (HFO and diesel) have significantly higher opex while those with non-oil based generation (hydropower, coal and gas) have lower opex and similar capex. In terms of geography, SSA's island nations bear a significant power cost disadvantage vis-à-vis the coastal and landlocked countries on account of high dependence on oil-based power generation. High power costs are also driven by the size of markets, with small markets relying more on thermal generation resulting in higher opex.

**Figure 5**: **Cost drivers in 2014 U.S. dollars per kWh billed**

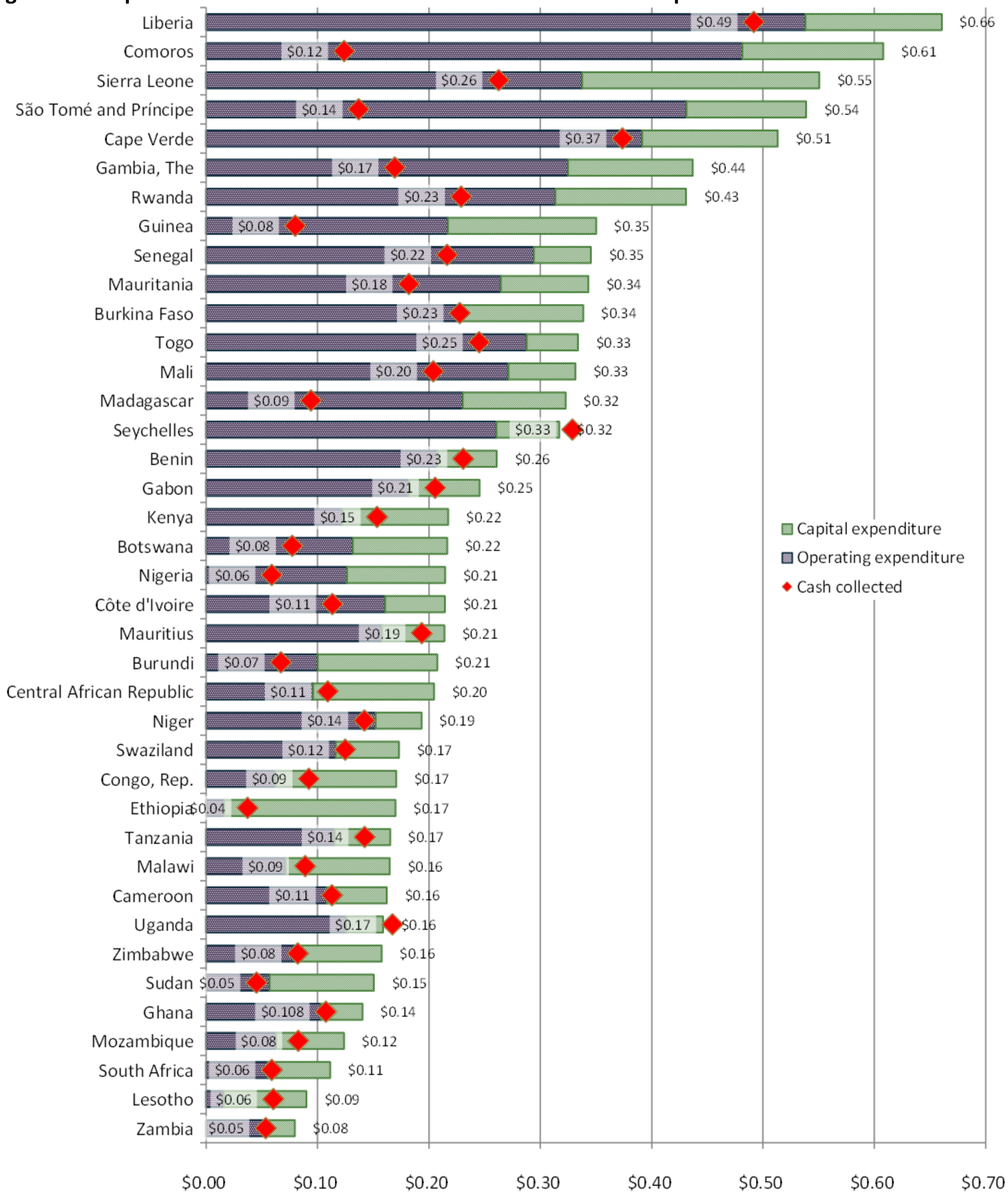



*Source*: World Bank staff calculations.
*Note*: The figure excludes three countries with a large portion of domestic power purchases classified as opex (Republic of Congo, Ghana, and Mozambique).

## 4.2 Comparison of costs and cash collected

Figure 6 compares current costs (aggregated into opex and capex for simplicity, with unrebated taxes captured in opex) with cash collected. Under the assumptions applied, only two countries cover the total current cost of service (the Seychelles and Uganda) which corresponds to level four on the financial viability ladder, while the cash collected covers opex in 19 countries (level two on the financial viability ladder).

**Figure 6: Comparison of costs with cash collected in 2014 U.S. dollars per kWh billed**




*Source*: World Bank staff calculations based on utility financial statements and other documents.

Up to 20 were not able to cover opex (level one on the financial viability ladder), although as noted some capex is built into the reported opex for countries with a high proportion of private-power purchases, in particular Tanzania and Guinea. The median financial gap is US$0.10 per kWh billed. For the five countries with a very high cost of service (US$0.50 per kWh billed or higher), the best performers are Cape Verde and Liberia. On the other hand, Comoros, São Tomé and Príncipe, and Sierra Leone have losses of US$0.48, 0.40 and 0.29 per kWh billed, respectively.

Unit cost and unit cash collected per kWh billed are statistically significantly correlated using a 1-percent test (meaning that the probability of mistakenly concluding the presence of correlation when there is actually no correlation is less than 1 percent). The correlation coefficient is 0.69, suggesting that high-cost utilities tend to have high tariffs and collect more revenue.

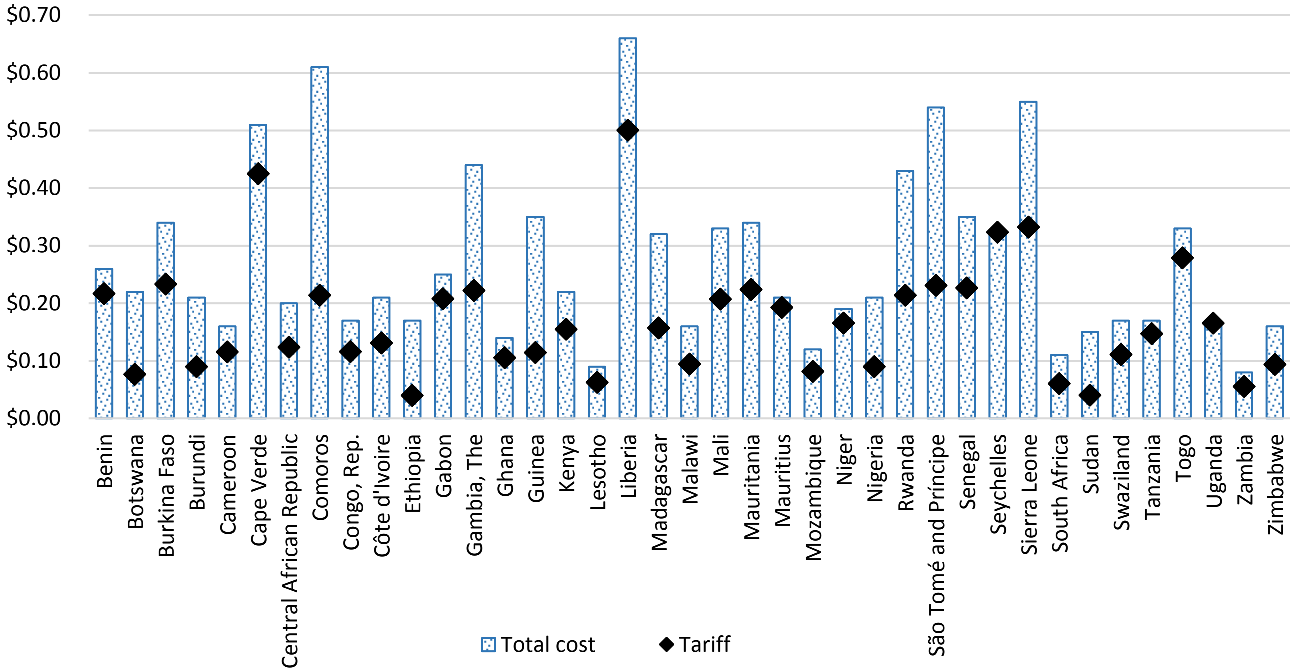
## 4.3 Average electricity tariffs

The median tariff in SSA was US$0.15 per kWh with significant variation across the region. The highest average tariffs are in Liberia at US$0.50 per kWh billed, and the lowest in Ethiopia and Sudan at US$0.04 per kWh billed. Because power consumers pay VAT and other taxes and fees not captured by utilities, the actual payments can be higher.

The weighted average tariff for the continent was US$0.08 per kWh. The weighted average tariff is skewed by the larger systems, which tend to have lower tariffs, in part because of economies of scale and also because several rely on cheap sources of electricity (coal, hydropower). 12 countries in the sample of 39 countries covered in this section have systems larger than 1 GW. Together they account for more than 90 percent of sales on the continent, and have weighted average tariffs of US$0.07 per kWh billed. This contrasts with systems smaller than 1 GW, which have weighted average tariffs of US$0.17 per kWh but together account for less than 10 percent of sales and hence do not have a significant effect on the weighted average for the continent.

Utilities can have tariff and non-tariff revenue. Non-tariff revenue includes revenue directly related to electricity sales but not through tariffs, such as connection fees. In 13 countries, total revenue consisted entirely of tariff revenue, meaning the utility did not collect non-tariff revenue or did not report it separately. In another 20, revenue per kWh billed was within US$0.01 of average tariff per kWh billed, with the remaining six (Benin, Central African Republic, The Gambia, Liberia, Rwanda, and Swaziland) reporting non-tariff revenue between US$0.01 and US$0.027 per kWh billed. As such, comparison of average tariffs and unit costs gives an idea of "tariff gap." The results are shown in Figure 7. The gaps vary from country to country, but with the exception of the Seychelles Uganda, all other countries have some way to go.

**Figure 7: Total cost and tariff revenue per kWh billed in 2014 U.S. dollars**




*Source*: World Bank staff calculations based on utility data.
*Note*: Tariff revenue excludes rebated taxes, such as VAT.

A breakdown of average tariff data was available for a subset of 16 countries, presented in

Table 5. Two broad groups can be identified. In around half of countries in the sample, residential tariffs were lower than commercial tariffs and in most cases also lower than government tariffs. In the second group, average residential tariffs were the higher than commercial and often the highest priced customer category. Export tariff data are available only for two countries. Notably export tariffs were the lowest of all customer categories in Malawi.

**Table 5: Average tariff by consumer category (constant 2014 U.S. dollars per kWh billed)**

| Country | Residential | Commercial | Industrial | Government | Export | Total average |
|---|---|---|---|---|---|---|
| **Group 1: residential priced lower than commercial** | | | | | | |
| **Guinea** | 0.06 | 0.24 | n/a | n/a | n/a | 0.11 |
| **Botswana** | 0.07 | 0.09 | 0.06 | 0.13 | n/a | 0.08 |
| **Malawi** | 0.10 | 0.17 | 0.12 | n/a | 0.07 | 0.09 |
| **São Tomé and Príncipe** | 0.12 | 0.30 | 0.17 | 0.39 | n/a | 0.23 |
| **Niger** | 0.16 | 0.17 | n/a | 0.39 | n/a | 0.17 |
| **Kenya** | 0.18 | 0.23 | 0.14 | 0.14 | 0.22 | 0.15 |
| **Mauritius** | 0.19 | 0.25 | 0.12 | 0.26 | n/a | 0.19 |
| **Group 2: residential priced higher than commercial** | | | | | | |
| **Lesotho** | 0.08 | 0.06 | 0.05 | n/a | n/a | 0.06 |
| **Burundi** | 0.11 | 0.09 | 0.09 | 0.09 | n/a | 0.09 |
| **Uganda** | 0.19 | 0.19 | 0.15 | 0.19 | n/a | 0.17 |
| **Mali** | 0.21 | 0.17 | n/a | n/a | n/a | 0.21 |
| **Mauritania** | 0.22 | 0.22 | n/a | 0.25 | n/a | 0.22 |
| **Gabon** | 0.21 | 0.16 | n/a | n/a | n/a | 0.21 |
| **Senegal** | 0.25 | 0.21 | 0.14 | n/a | n/a | 0.23 |
| **Cape Verde** | 0.49 | 0.43 | n/a | 0.41 | n/a | 0.42 |
| **Liberia** | 0.51 | 0.50 | n/a | 0.40 | n/a | 0.50 |

*Sources*: Utility financial statements and annual reports.
*Note:* Where data are categorized by the utility according to LV, MV, and HV customers (Gabon, Guinea, Mali, Mauritania, Senegal), they are recorded in this table under residential, commercial, and industrial customers, respectively. For the purposes of grouping analysis, mining customers are included under industrial, and street lighting and diplomatic categories are included under government. Relatively rare customer categories such as nonprofits are excluded. For Cape Verde, sales to commercial, industry, and agriculture customers are recorded under commercial. n.a.= not applicable.

Detailed results comparing all revenue, tariff revenue, cash collected, opex, and capex per kWh billed are shown in Table 6. It includes the full data for Figure 6 and Figure 7.

**Table 6: Revenues and costs, constant 2014 US$ per kWh billed**

| Country | Revenue | Tariff | Bill collection rate | Cash collected | Opex | Capex | Total cost |
|---|---|---|---|---|---|---|---|
| Benin | $0.24 | $0.22 | 95% | $0.23 | $0.21 | $0.05 | $0.26 |
| Botswana[a] | $0.08 | $0.08 | 99% | $0.08 | $0.13 | $0.08 | $0.22 |
| Burkina Faso | $0.23 | $0.23 | 98% | $0.23 | $0.23 | $0.11 | $0.34 |
| Burundi | $0.09 | $0.09 | 74% | $0.07 | $0.10 | $0.11 | $0.21 |
| Cameroon | $0.12 | $0.12 | 95% | $0.11 | $0.11 | $0.05 | $0.16 |
| Cape Verde | $0.42 | $0.42 | 88% | $0.37 | $0.39 | $0.12 | $0.51 |
| Central African Republic | $0.14 | $0.12 | 78% | $0.11 | $0.10 | $0.11 | $0.20 |
| Comoros | $0.21 | $0.21 | 58% | $0.12 | $0.48 | $0.13 | $0.61 |
| Congo, Rep. | $0.12 | $0.12 | 80% | $0.09 | $0.06 | $0.11 | $0.17 |
| Côte d’Ivoire | $0.14 | $0.13 | 82% | $0.11 | $0.16 | $0.05 | $0.21 |
| Ethiopia[a] | $0.04 | $0.04 | 87% | $0.04 | $0.02 | $0.15 | $0.17 |
| Gabon[a] | $0.21 | $0.21 | 99% | $0.21 | $0.18 | $0.06 | $0.25 |
| Gambia, The | $0.23 | $0.22 | 73% | $0.17 | $0.33 | $0.11 | $0.44 |
| Ghana | $0.11 | $0.11 | 95% | $0.11 | $0.10 | $0.04 | $0.14 |
| Guinea | $0.11 | $0.11 | 70% | $0.08 | $0.22 | $0.13 | $0.35 |
| Kenya | $0.16 | $0.15 | 99% | $0.15 | $0.12 | $0.09 | $0.22 |
| Lesotho[a] | $0.07 | $0.06 | 87% | $0.06 | $0.02 | $0.07 | $0.09 |
| Liberia | $0.52 | $0.50 | 94% | $0.49 | $0.54 | $0.12 | $0.66 |
| Madagascar | $0.16 | $0.16 | 60% | $0.09 | $0.23 | $0.09 | $0.32 |
| Malawi | $0.10 | $0.09 | 93% | $0.09 | $0.07 | $0.09 | $0.16 |
| Mali | $0.21 | $0.21 | 99% | $0.20 | $0.27 | $0.06 | $0.33 |
| Mauritania | $0.22 | $0.22 | 81% | $0.18 | $0.26 | $0.08 | $0.34 |
| Mauritius[a] | $0.20 | $0.19 | 99% | $0.19 | $0.16 | $0.06 | $0.21 |
| Mozambique | $0.09 | $0.08 | 92% | $0.08 | $0.06 | $0.06 | $0.12 |
| Niger | $0.17 | $0.17 | 86% | $0.14 | $0.15 | $0.04 | $0.19 |
| Nigeria | $0.09 | $0.09 | 66% | $0.06 | $0.13 | $0.09 | $0.21 |
| Rwanda | $0.24 | $0.21 | 95% | $0.23 | $0.31 | $0.12 | $0.43 |
| São Tomé and Príncipe | $0.23 | $0.23 | 59% | $0.14 | $0.43 | $0.11 | $0.54 |
| Senegal | $0.23 | $0.23 | 93% | $0.22 | $0.29 | $0.05 | $0.35 |
| Seychelles[a] | $0.33 | $0.32 | 99% | $0.33 | $0.26 | $0.06 | $0.32 |
| Sierra Leone | $0.33 | $0.33 | 79% | $0.26 | $0.34 | $0.21 | $0.55 |
| South Africa | $0.06 | $0.06 | 98% | $0.06 | $0.06 | $0.06 | $0.11 |
| Sudan | $0.05 | $0.04 | 100% | $0.05 | $0.06 | $0.09 | $0.15 |
| Swaziland[a] | $0.13 | $0.11 | 99% | $0.12 | $0.12 | $0.06 | $0.17 |
| Tanzania | $0.15 | $0.15 | 92% | $0.14 | $0.12 | $0.05 | $0.17 |
| Togo | $0.28 | $0.28 | 88% | $0.25 | $0.29 | $0.05 | $0.33 |
| Uganda | $0.17 | $0.17 | 99% | $0.17 | $0.13 | $0.03 | $0.16 |
| Zambia | $0.06 | $0.06 | 96% | $0.05 | $0.05 | $0.03 | $0.08 |
| Zimbabwe | $0.10 | $0.09 | 87% | $0.08 | $0.08 | $0.08 | $0.16 |
| Maximum | $0.52 | $0.50 | 100% | $0.49 | $0.54 | $0.21 | $0.66 |
| Minimum | $0.04 | $0.04 | 58% | $0.04 | $0.02 | $0.03 | $0.08 |
| Median | $0.16 | $0.15 | 93% | $0.12 | $0.15 | $0.08 | $0.21 |

*Source*: World Bank staff calculations.

a. Bill collection rates are assumed for these countries, as explained in section A1.3 of annex 1.

# 5 Quasi-fiscal deficits

This section presents QFDs based on current operations and benchmark operations. Data presented in relative terms are expressed relative to GDP, revenues and cash collected in the reference year.

## 5.1 Quasi-fiscal deficits under current performance

Across the continent, the QFD was equivalent to US$21 billion in constant 2014 U.S. dollars, or 1.5 percent of current GDP (0.9 percent of current GDP excluding South Africa). In three countries, the QFD exceeded 5 percent of GDP (The Gambia, São Tomé and Princípe and Zimbabwe) driven by low tariffs, high collection losses, and high T&D losses. The large deficit of 3.4 percent of GDP in South Africa partly reflects years of delayed investments, maintenance, overhaul, and capacity expansion against the backdrop of rapid access expansion. One consequence is increasing reliance on oil-based power generation.

The QFD looks very large in most countries when compared to utility revenues and cash collected. The QFD exceeded 100 percent of revenues in 10 countries, and were several multiples of revenues in Comoros, Ethiopia, Guinea, and Sudan (Table 7). On a per kWh basis, the median QFD is $0.10 per kWh sold, suggesting that with no change in operational performance or underlying cost structures, tariffs would need to increase by this amount in order to achieve financial viability.

**Table 7: Quasi-fiscal deficits under current performance in the reference year**

| Country | Absolute QFD | Relative QFD | | |
|---|---|---|---|---|
| | (current US$ million) | (% current GDP) | (% revenues) | (% cash collected) |
| Benin | $26 | 0.3 | 12 | 13 |
| Botswana | $487 | 3.4 | 174 | 176 |
| Burkina Faso | $125 | 1.0 | 48 | 49 |
| Burundi | $29 | 1.0 | 154 | 208 |
| Cameroon | $214 | 0.7 | 41 | 43 |
| Cape Verde | $28 | 1.6 | 34 | 39 |
| Central African Republic | $7 | 0.4 | 68 | 87 |
| Comoros | $23 | 4.1 | 230 | 397 |
| Congo, Rep. | $76 | 0.6 | 76 | 96 |
| Côte d'Ivoire | $654 | 1.9 | 74 | 89 |
| Ethiopia | $636 | 1.7 | 353 | 408 |
| Gabon | $66 | 0.4 | 19 | 19 |
| Gambia, The | $52 | 5.8 | 115 | 158 |
| Ghana | $205 | 0.5 | 22 | 23 |
| Guinea | $129 | 2.1 | 247 | 354 |
| Kenya | $486 | 0.8 | 40 | 41 |
| Lesotho | $11 | 0.5 | 21 | 24 |
| Liberia | $7 | 0.4 | 33 | 36 |
| Madagascar | $229 | 2.2 | 146 | 243 |
| Malawi | $111 | 2.5 | 82 | 88 |
| Mali | $155 | 1.3 | 62 | 63 |
| Mauritania | $78 | 1.5 | 73 | 90 |
| Mauritius | $51 | 0.4 | 11 | 12 |
| Mozambique | $157 | 0.9 | 45 | 49 |
| Niger | $39 | 0.5 | 31 | 36 |

| Country | Absolute QFD (current US$ million) | (% current GDP) | Relative QFD (% revenues) | (% cash collected) |
|---|---|---|---|---|
| Nigeria | $2,928 | 0.5 | 174 | 264 |
| Rwanda | $78 | 1.0 | 82 | 86 |
| São Tomé and Príncipe | $21 | 6.1 | 174 | 293 |
| Senegal | $325 | 2.2 | 55 | 59 |
| Seychelles | -$4 | -0.3 | -4 | -4 |
| Sierra Leone | $33 | 0.9 | 97 | 123 |
| South Africa | $11,329 | 3.4 | 90 | 92 |
| Sudan | $1,024 | 1.4 | 233 | 233 |
| Swaziland | $52 | 1.2 | 40 | 40 |
| Tanzania | $193 | 0.3 | 17 | 19 |
| Togo | $70 | 1.6 | 32 | 36 |
| Uganda | -$19 | -0.1 | -5 | -5 |
| Zambia | $317 | 1.2 | 47 | 49 |
| Zimbabwe | $643 | 5.2 | 82 | 94 |
| | | | | |
| Maximum | $11,329 | 6.08 | 353 | 408 |
| Minimum | -$19 | -0.26 | -5 | -5 |
| Median | $78 | 1.04 | 62 | 63 |

*Source*: World Bank staff calculations based on utility financial statements, annual reports, and other documents.

The quasi-fiscal deficit relative to cash collected is correlated using a 1-percent significance test with capital cost per kWh billed, with a positive sign, suggesting that the higher the capital cost, the higher the deficit relative to cash collected.

### The case of Ethiopia

With its QFD more than 350 percent of utility revenues, Ethiopia merits special attention. The large deficit is driven by high capex combined with average tariffs that are among the lowest on the continent. Since 2005, the government of Ethiopia has embarked on an aggressive power sector expansion program, including major investments in hydropower (including Gibe 3 and the Grand Renaissance Dam) and network expansion through the Universal Electricity Access Program providing grid-based electrification in rural areas. With more than 2,000 staff members, a large investment envelope (approximately US$245 million in 2015), and thousands of kilometers of MV and LV distribution lines constructed every year, the program is one of the largest electrification programs in Africa. In Ethiopia, it accounts for more than 95percent of the financial resources allocated to the expansion of electric service on an annual basis.

The government's ambitious power sector objectives were reflected in the country's development agenda. The first Growth and Transformation Plan covering the period 2010–2015 included the target of doubling the number of electricity customers from two to four million. The second plan has set an even more ambitious target: to reach seven million customers by 2020.

The massive power sector investments and notably those associated to the Universal Electricity Access Program translate in the short term to high costs per kWh, which are expected to fall over time as electricity access increases. However, access to electricity services remains far below expectations. Against the target of 4 million, 2.4 million new customers were connected by 2015. Initially, as generation capacity started growing significantly, the backlog of investments in T&D infrastructure created a major bottleneck. This has been solved in part with the access program. Nonetheless, the program itself has a major limitation: the expansion of the network has not been accompanied by an equal effort to increase connectivity. As a result, while 55 percent of the population resides in areas served by the network, less than 25 percent is connected to electricity services. Connections have lagged behind for several reasons, including the absence of a robust program and dedicated resources to roll out connections; lack of affordability; and capacity constraints at the utility level in handling a growing customer base. Given the massive investments mobilized under the program, results have been disappointing. In 2015, against the US$245 million spent, only 65,000 new customers were added to service, resulting in a cost per connection of US$3,770.

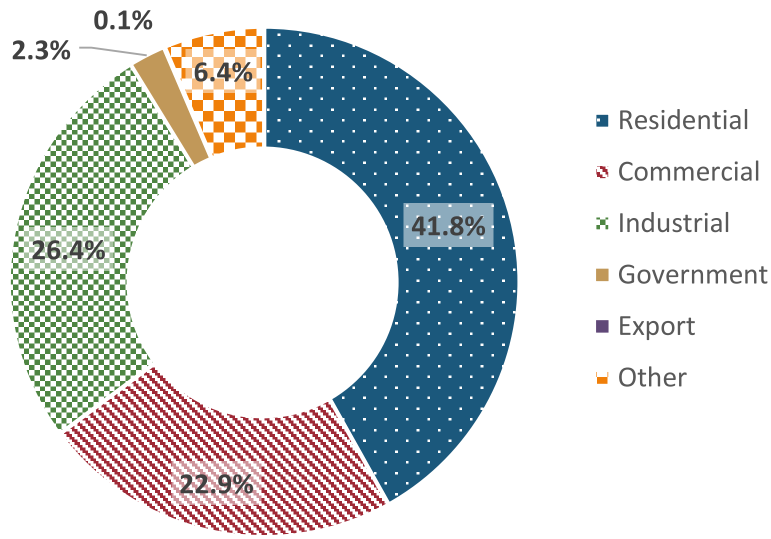
As new generation plants come online and as the number of connections increases, total system sales will increase and the cost of service per kWh billed is therefore expected to reduce dramatically from an estimated US$0.18 per kWh billed to less than US$0.10 per kWh billed. Average tariff levels are expected to increase as exports increase in the share of total sales, helping to reduce the financial gap in the sector over the medium to long term.

## 5.2 Distribution of quasi-fiscal deficit between consumer categories

Sales data are available for a subset of 16 countries to analyze the distribution of QFD between consumer groups. For the purposes of this analysis, it was assumed that industry and export customers have an average cost of service US$0.035 less than other customers. This is because industrial and export customers are typically supplied at high voltage, thereby avoiding the use of medium and low voltage distribution networks. In most cases the source of data for breakdown of sales by consumer group (revenues and energy sold) were different to the sources used in the base-case QFD estimates. In these cases, it is assumed that the sources used in the base-case QFD estimates contain the correct data at an aggregated total level, and that the sources used for the breakdown provide the correct average tariff data by consumer group and the correct revenue profile i.e. percentage of LCU sales to each consumer category. These assumptions are used to estimate the breakdown of total reported revenue and energy sales by consumer group.

The results are summarized in Figure 8. Residential customers account for 42 percent of the QFD, and 38 percent of consumption in the sample of countries included in this analysis, suggesting other customer categories marginally cross-subsidize residential customers. In these 16 countries, tariff schedules indicate that only a small number of customer categories (e.g., commercial customers in Mauritius, government customers in Niger) pay above the cost of service.

**Figure 8: Distribution of quasi-fiscal deficits between consumer categories**




*Source*: World Bank staff calculations based on utility data.

## 5.3 Quasi-fiscal deficits under benchmark performance

As explained in section 2, benchmark performance is defined as 100 percent bill collection rate, 10 percent T&D losses, and staffing at benchmark levels. A breakdown is provided in Table 8.

**Table 8: Quasi-fiscal deficits under benchmark performance**

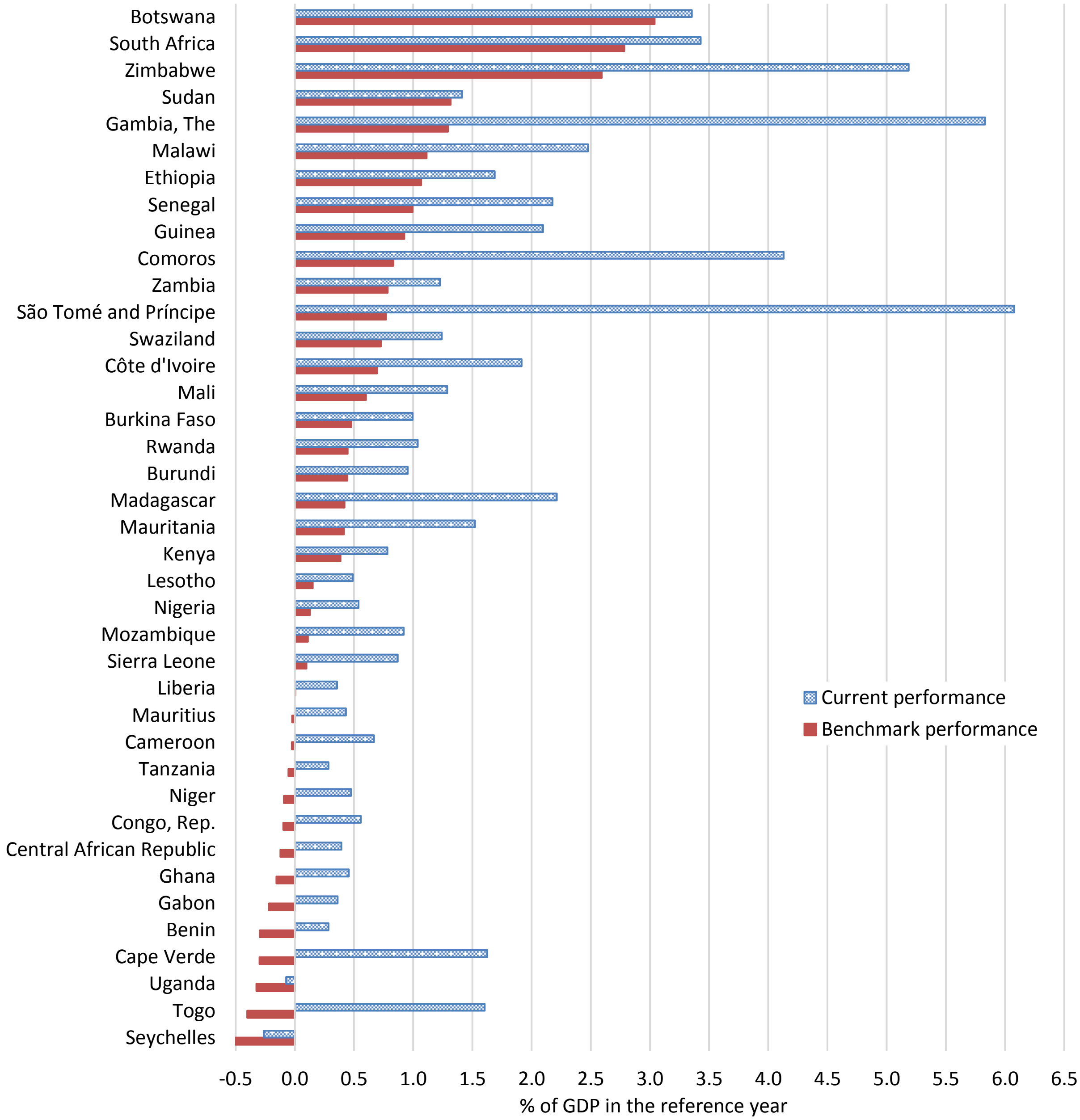
| Country | Absolute QFD under benchmark performance (current US$ million) | Relative QFD under benchmark performance | | |
|---|---|---|---|---|
| | | (% current GDP) | (% revenues) | (% cash collected) |
| Benin | -$27 | -0.3 | -13 | -13 |
| Botswana | $442 | 3.0 | 158 | 159 |
| Burkina Faso | $60 | 0.5 | 23 | 23 |
| Burundi | $14 | 0.4 | 72 | 97 |
| Cameroon | -$8 | 0.0 | -2 | -2 |
| Cape Verde | -$5 | -0.3 | -6 | -7 |
| Central African Republic | -$2 | -0.1 | -21 | -27 |
| Comoros | $5 | 0.8 | 46 | 80 |
| Congo, Rep. | -$13 | -0.1 | -13 | -17 |
| Côte d'Ivoire | $237 | 0.7 | 27 | 32 |
| Ethiopia | $402 | 1.1 | 223 | 258 |
| Gabon | -$40 | -0.2 | -12 | -12 |
| Gambia, The | $11 | 1.3 | 26 | 35 |
| Ghana | -$70 | -0.2 | -7 | -8 |
| Guinea | $57 | 0.9 | 109 | 156 |
| Kenya | $240 | 0.4 | 20 | 20 |
| Lesotho | $3 | 0.1 | 6 | 7 |
| Liberia | $0 | 0.0 | 0 | 0 |
| Madagascar | $43 | 0.4 | 28 | 46 |
| Malawi | $50 | 1.1 | 37 | 40 |
| Mali | $72 | 0.6 | 29 | 29 |
| Mauritania | $21 | 0.4 | 20 | 25 |

| Country | Absolute QFD under benchmark performance (current US$ million) | Relative QFD under benchmark performance (% current GDP) | (% revenues) | (% cash collected) |
|---|---|---|---|---|
| Mauritius | -$3 | 0.0 | -1 | -1 |
| Mozambique | $19 | 0.1 | 5 | 6 |
| Niger | -$8 | -0.1 | -6 | -7 |
| Nigeria | $696 | 0.1 | 41 | 63 |
| Rwanda | $34 | 0.4 | 35 | 37 |
| São Tomé and Príncipe | $3 | 0.8 | 22 | 37 |
| Senegal | $149 | 1.0 | 25 | 27 |
| Seychelles | -$12 | -0.9 | -12 | -12 |
| Sierra Leone | $4 | 0.1 | 11 | 14 |
| South Africa | $9,193 | 2.8 | 73 | 75 |
| Sudan | $953 | 1.3 | 217 | 217 |
| Swaziland | $30 | 0.7 | 23 | 24 |
| Tanzania | -$38 | -0.1 | -3 | -4 |
| Togo | -$17 | -0.4 | -8 | -9 |
| Uganda | -$86 | -0.3 | -22 | -22 |
| Zambia | $203 | 0.8 | 30 | 31 |
| Zimbabwe | $321 | 2.6 | 41 | 47 |
| | | | | |
| Maximum | $9,193 | 3.04 | 223 | 258 |
| Minimum | -$86 | -0.85 | -22 | -27 |
| Median | $14 | 0.42 | 22 | 24 |

*Source*: World Bank staff calculations based on utility financial statements, annual reports, and other documents.

The QFD is reduced under benchmark performance operations as cash collected increases and costs fall (Figure 9). On average, the QFD is reduced from 1.5 to 0.9 percent of GDP (from 0.9 to 0.3 percent of GDP excluding South Africa). The QFD is reduced to below zero in an additional eleven countries, bringing the total to 13. The main mechanism for eliminating the QFD under benchmark performance would be to raise revenue by a combination of tariff increases and loss reduction. That said, the actual reduction in QFDs would be smaller at least over the short term, because the calculations in Figure 9 assumes that benchmark performance can be achieved at no additional cost, whereas reducing technical losses and implementing revenue protection measures (such as by means of advanced metering infrastructure and metering control centers) all incur additional expenditures.

**Figure 9: Comparison of QFD at current vs. benchmark performance**




*Source*: World Bank staff calculations based on utility financial statements, annual reports, and other documents.

Is there a trade-off between the QFD and access? That is, could it be that utilities run deficits to take on more ambitious electrification programs? Is a country's QFD in the power sector affected by the income level or the depth of poverty? Examination of QFDs with economic parameters found that none of the six measures of QFDs—as shares of GDP, revenue, and cash collected at current as well as benchmark performance—were correlated with household access to electricity in 2012 (World Bank and IEA 2015), the poverty gap at $3.10 per person per day at purchasing power parity in 2011 international dollars (in 2012, or if the poverty gap is not available in 2012, within two years of 2012), per capita GDP at the market exchange rate, and per capita GDP at purchasing power parity using a 5-percent significance test. There is therefore no obvious trade-off between access and QFD, or between access and underpricing of tariffs (QFD at benchmark performance).

# 6 Breakdown of quasi-fiscal deficits into hidden costs

The QFD described above is broken down to into four hidden costs—underpricing, T&D losses, low bill collections, and overstaffing. Eliminating avoidable T&D losses in a supply-constrained market enables delivery of more electricity to end-users and reduces capacity expansion needed to meet the same demand, while reducing staffing may lower the cost of service. The magnitude of each hidden cost is estimated for a utility operating at benchmark performance, which for the purposes of this analysis is assumed to be 100 percent bill collection rate, 10 percent T&D losses, and staffing at optimal levels relative to developing country benchmarks. Data to compute hidden costs were available in all 39 countries in this study only for T&D losses.

Table 9 provides a breakdown of results. Once benchmark performance in losses and staffing is achieved, there is negative underpricing in 13 countries. Depending on the investments required to achieve benchmark performance, this suggests there may be scope to reduce prices in some countries. Underpricing and avoidable T&D losses tend to be the most significant hidden costs with median values of 0.4 and 0.3 percent of GDP, respectively, and are the dominant hidden cost in 16 and 14 counties, respectively. Overstaffing and collection inefficiencies tend to be smaller, being the dominant hidden cost in 5 and 4 countries respectively. One prominent example is The Gambia, where they represent 1.8 and 1.1 percent of GDP, respectively.

**Table 9: Breakdown of hidden costs (percentage of current GDP)**

| Country | Bill collection | T&D losses | Over-staffing | Underpricing | Total hidden costs |
|---|---|---|---|---|---|
| Benin | 0.10 | 0.24 | 0.24 | -0.30 | 0.28 |
| Botswana | 0.05 | 0.00 | 0.26 | 3.04 | 3.35 |
| Burkina Faso | 0.06 | 0.22 | 0.23 | 0.48 | 0.99 |
| Burundi | 0.32 | 0.13 | 0.06 | 0.44 | 0.95 |
| Cameroon | 0.08 | 0.39 | 0.23 | -0.03 | 0.67 |
| Cape Verde | 0.53 | 1.40 | 0.00 | -0.30 | 1.63 |
| Central African Republic | 0.09 | 0.26 | 0.16 | -0.12 | 0.39 |
| Comoros | 1.36 | 1.62 | 0.32 | 0.83 | 4.13 |
| Congo, Rep. | 0.12 | 0.39 | 0.14 | -0.10 | 0.56 |
| Côte d'Ivoire | 0.61 | 0.45 | 0.17 | 0.69 | 1.92 |
| Ethiopia | 0.23 | 0.34 | 0.05 | 1.07 | 1.69 |
| Gabon | 0.02 | 0.31 | 0.26 | -0.22 | 0.36 |
| Gambia, The | 1.84 | 1.57 | 1.12 | 1.29 | 5.83 |
| Ghana | 0.10 | 0.31 | 0.20 | -0.16 | 0.45 |
| Guinea | 0.65 | 0.39 | 0.13 | 0.92 | 2.10 |
| Kenya | 0.02 | 0.21 | 0.16 | 0.39 | 0.78 |
| Lesotho | 0.34 | 0.00 | n/a | 0.15 | 0.49 |
| Liberia | 0.06 | 0.21 | 0.08 | 0.00 | 0.36 |
| Madagascar | 0.89 | 0.75 | 0.16 | 0.42 | 2.21 |
| Malawi | 0.30 | 0.74 | 0.32 | 1.11 | 2.48 |
| Mali | 0.04 | 0.46 | 0.19 | 0.60 | 1.29 |
| Mauritania | 0.48 | 0.43 | 0.19 | 0.42 | 1.52 |
| Mauritius | 0.04 | 0.00 | 0.41 | -0.02 | 0.43 |
| Mozambique | 0.17 | 0.31 | 0.33 | 0.11 | 0.92 |
| Niger | 0.20 | 0.16 | 0.21 | -0.09 | 0.48 |
| Nigeria | 0.17 | 0.24 | n/a | 0.13 | 0.54 |
| Rwanda | 0.09 | 0.35 | 0.16 | 0.45 | 1.04 |
| São Tomé and Princípe | 1.94 | 2.77 | 0.60 | 0.77 | 6.08 |
| Senegal | 0.35 | 0.45 | 0.38 | 1.00 | 2.18 |

| Country | Bill collection | T&D losses | Over-staffing | Underpricing | Total hidden costs |
|---|---|---|---|---|---|
| Seychelles | 0.06 | 0.18 | 0.35 | -0.85 | -0.26 |
| Sierra Leone | 0.21 | 0.47 | 0.08 | 0.10 | 0.87 |
| South Africa | 0.15 | 0.00 | 0.50 | 2.78 | 3.429 |
| Sudan | 0.00 | 0.10 | n/a | 1.32 | 1.41 |
| Swaziland | 0.04 | 0.04 | 0.43 | 0.73 | 1.24 |
| Tanzania | 0.13 | 0.14 | 0.07 | -0.06 | 0.28 |
| Togo | 0.55 | 1.15 | 0.30 | -0.40 | 1.60 |
| Uganda | 0.01 | 0.16 | 0.08 | -0.32 | -0.07 |
| Zambia | 0.12 | 0.09 | 0.23 | 0.79 | 1.23 |
| Zimbabwe | 1.26 | 0.58 | 0.75 | 2.59 | 5.19 |
| | | | | | |
| Maximum | 1.94 | 2.77 | 1.12 | 3.04 | 6.08 |
| Minimum | 0.00 | 0.00 | 0.00 | -0.85 | -0.26 |
| Median | 0.15 | 0.31 | 0.22 | 0.42 | 1.04 |

*Source*: World Bank staff calculations based on utility financial statements, annual reports, and other documents.
*Note*: — = not available.

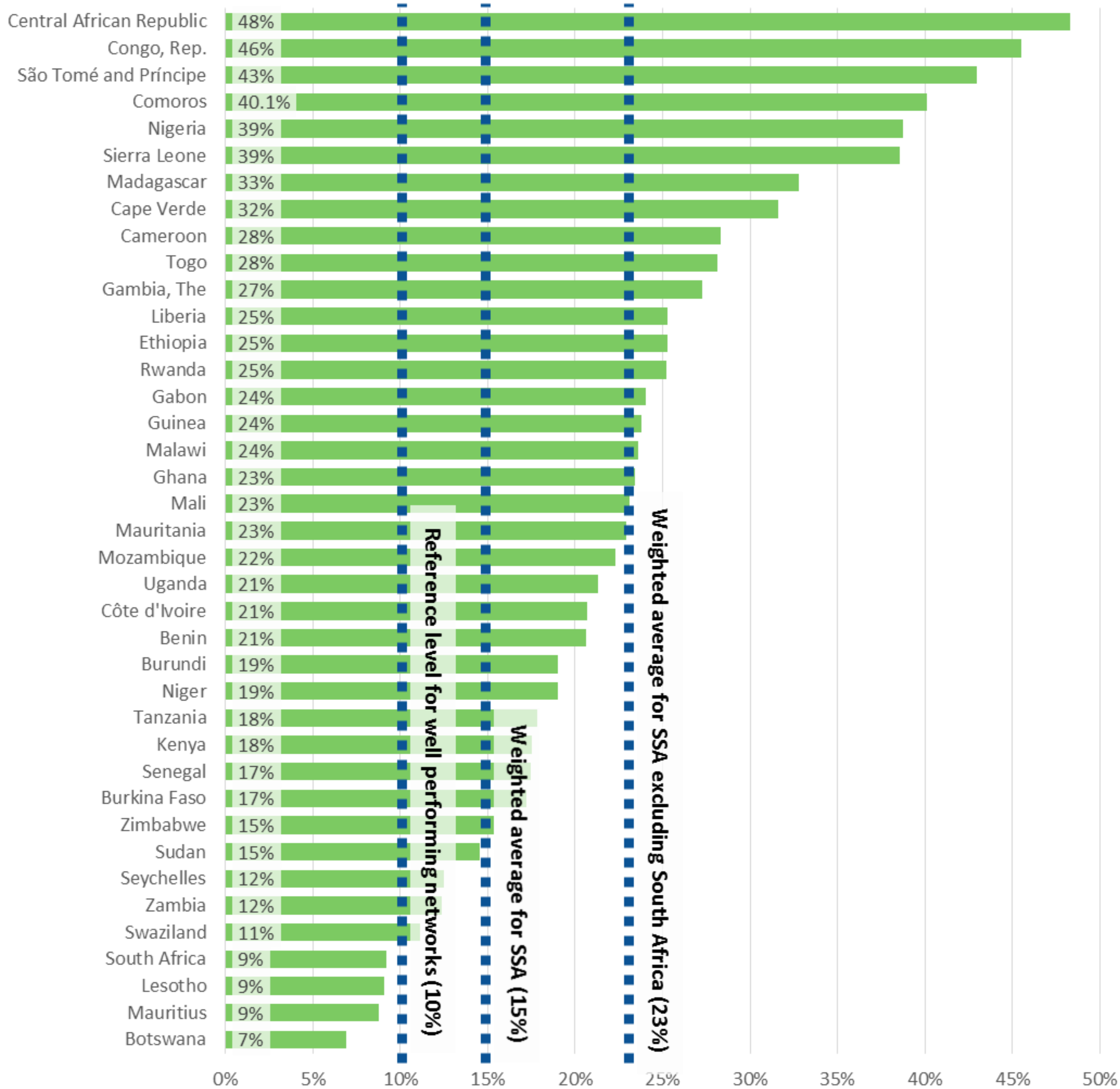
## 6.1 T&D losses

As outlined in Table 2, T&D losses consist of technical and nontechnical losses. International reference values for well-performing power systems suggest that technical losses can be kept to less than 10 percent and non-technical losses close to zero. For simplicity, a combined benchmark losses of 10 percent are used in this study. Only four countries—Botswana, Lesotho, Mauritius, and South Africa—were found to have T&D losses of 10 percent or smaller (Figure 10). In the remaining 35 countries, losses ranged from 11 percent in Swaziland to more than 40 percent in Comoros, São Tomé and Príncipe, the Republic of Congo, and the Central African Republic. Weighted average losses in SSA were 15 percent, and 23 percent if South Africa is excluded.

In several reference utilities, a portion of sales are made at high voltage levels which will tend to skew T&D losses downward because T&D losses are proportionally greater in the low voltage distribution network. Examples high voltage sales include industrial and mining customers, and sales to other utilities who sell to the end user. Examples of the latter include all export sales, municipality customers in South Africa who buy electricity from Eskom and selling to end-users, and Copperbelt Energy Corporation which buys electricity from Zambia Electricity Supply Company and sells to mining companies.

T&D losses represent a significant hidden cost for many utilities in SSA. Relative to GDP, these losses represent more than one percent of GDP in five countries (Cape Verde, Comoros, The Gambia, São Tomé and Príncipe, and Togo), and more than 50 percent of the QFD in 11 countries (Benin, Cameroon, Cape Verde, Central African Republic, Republic of Congo, Gabon, Ghana, Liberia, Sierra Leone, Tanzania and Togo).

**Figure 10: System-wide T&D losses in SSA** (%)




Sources: World Bank staff calculations based on utility annual reports and other sources.
*Note*: Percent T&D losses = GWh T&D losses / GWh dispatched by reference utility (inclusive of purchased electricity by reference utility); GWh T&D losses = GWh dispatched by reference utility – GWh billed to all customers (including exports and other utilities).

## 6.2 Bill collection losses

As outlined in Table 2, bill collection losses are for electricity billed to consumers but not paid for. As detailed in Table 6, bill collection rates ranged from close to 100 percent in nine countries (all above 98 percent) to below 75 percent in six. Comoros, Madagascar, and São Tomé and Príncipe have some of the lowest bill collection rates on the continent at 58, 60, and 59 percent, respectively.

In many countries, government entities can be the lowest-paying customers. For example in the Republic of Congo, the bill collection rate for the state was only 33 percent, against 89 percent for non-state consumers. Reasons for large payment arrears by government agencies and state-owned companies vary—the utility's limited influence over such customers as the military; an informal agreement where government agencies withhold payments to compensate for subsidies provided to the utility (direct transfers, tax breaks, exemption from import duties), or financially weak state-owned enterprises not paying bills to the state-owned utility; and the inability of the utility to cut off electricity for street lighting and other services considered public service obligations, for which the utility is rarely if ever paid by the government in some countries, including The Gambia.

Against a benchmark of 100 percent collection efficiency, a total loss of revenue to the utilities amounted to 0.2 percent of current GDP. Bill collection inefficiencies are the highest as a share of GDP in Comoros, The Gambia, São Tomé and Príncipe, and Zimbabwe where the losses represent more than one percent of GDP. Although Nigeria has a relatively low bill collection rate, the losses were equivalent to 0.17 percent of GDP.

Collection rates in some countries have improved significantly in the past few years. For example, since Umeme took the private concessionaire in Uganda, bill collection rates increase from 94 percent in 2009 to 99 percent in 2014. The main reason in many other countries is the increased use of pre-paid meters, which secure the revenues to the utilities in advance of consumption. At approximately US$100 per meter, pre-paid meters improve collection efficiency significantly at relative low costs. More than 80 percent of residential customers in South Africa are on pre-paid meters. Malawi has been engaged for several years in rollout programs for prepaid meters, having achieved enrollment of 47 percent of customers by 2014, which helped to achieve a 93 percent bill collection rate in 2014.

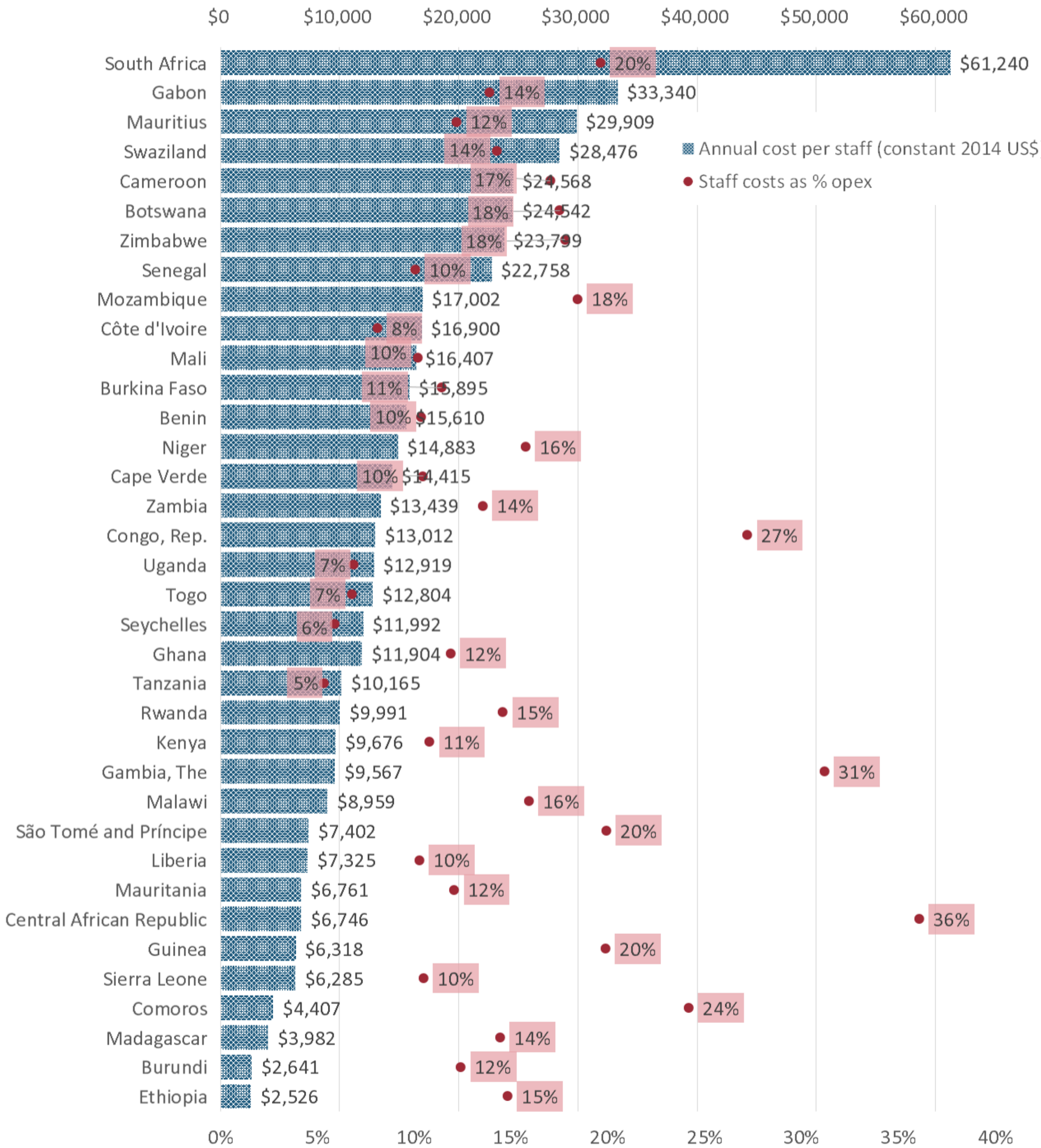
There is a strongly statistically significant correlation between T&D losses and bill collection losses. The correlation coefficient of 0.68 is significant using a 1-percent test. This may suggest that operational inefficiencies tend to be pervasive rather than found in isolated pockets.

## 6.3 Utility staffing

Staffing data were available in 36 countries. There are at least several important dimensions to consider with respect to utility staffing, including staff numbers, staff skills, attendance (reporting to work), and salaries and benefits. A utility may appear overstaffed, but if many staff members on the payroll are not showing up for work—a known problem in several utilities—the utility may actually be chronically understaffed with large and unproductive overhead costs that have a strong political dimension. Staff skills may also be a concern, with many utilities suffering from lack of appropriately trained and experienced staff.

Figure 11 summarizes utility staff costs, which include employee salaries and associated costs such as health benefits and pensions. Staff costs can represent a significant portion of operating costs for a utility: on average US$27,000 per employee per year in constant 2014 US dollars, although this result is heavily skewed by South Africa where the staff costs average US$61,000 per employee. Excluding South Africa, staff costs are on average US$13,000 per employee. Staff costs represent a median of 14 percent of operating costs. Staff costs represent the lowest share of opex in Tanzania (5 percent). At the opposite end of the spectrum, staff costs represented 31 percent of operating costs in The Gambia and 36 percent in the Central African Republic.

**Figure 11: Utility staff costs**




*Source*: World Bank staff calculations based on utility financial statements and annual reports.

The costs incurred by the utilities due to overstaffing were studied considering the labor costs of the extra staff employed by the utility when compared to a benchmark for developing countries. The methodology followed and assumptions used are described in more detail in section A1.6 in annex 1. The results are summarized in Table 10. Cape Verde is an outlier in the subset and appears to be understaffed. Excluding Cape Verde, countries with the most efficient utility staffing levels are in Gabon, Benin, Burkina Faso, Swaziland, and Senegal, all of which have staffing levels within 10 percent of the efficient level. Median overstaffing across all utilities is 41 percent, with most utilities in the 25–65 percent range. Eskom stands out for overstaffing in absolute terms, reporting 41,800 employees against the estimated benchmark of 14,200, suggesting overstaffing of 27,500. The most extreme case is the Zambia Electricity Supply Company (ZESCO) in Zambia, which is overstaffed by more than 70 percent. These findings suggest opportunities to optimize staff levels, which could result in substantially lower costs, or else use the savings to offer higher salaries to attract more qualified workers without increasing overall spending on labor. For utilities that provide a breakdown of staff working in generation and T&D, overstaffing seems to be more prevalent among staff working on T&D.

### Table 10: Analysis of staffing levels

| | | Actual number of staff | | | "Optimal" benchmark staff size | | | Overstaffing | |
|---|---|---|---|---|---|---|---|---|---|
| **Country** | **# customers** | **Generation** | **T&D** | **Total** | **Generation** | **T&D** | **Total** | **Difference** | **% over** |
| Cape Verde | 133,481 | | | **634** | 496 | 449 | **945** | -311 | -49% |
| Gabon | 280,639 | | | **1,430** | 753 | 638 | **1,391** | 40 | 3% |
| Benin | 484,486 | | 1,412 | **1,412** | 262 | 1,101 | **1,363** | 49 | 4% |
| Burkina Faso | 508,499 | | | **1,885** | 646 | 1,156 | **1,802** | 83 | 4% |
| Swaziland | 150,668 | | | **680** | 135 | 507 | **642** | 38 | 6% |
| Senegal | 998,423 | | | **2,583** | 662 | 1,749 | **2,411** | 172 | 7% |
| Sierra Leone | 80,894 | | | **663** | 268 | 272 | **539** | 124 | 19% |
| Mauritius | 435,311 | | | **1,902** | 531 | 989 | **1,520** | 382 | 20% |
| Mali | 346,978 | 214 | 1,347 | **1,561** | 415 | 789 | **1,203** | 358 | 23% |
| Togo | 233,036 | | 1,161 | **1,161** | 101 | 784 | **885** | 276 | 24% |
| Mozambique | 1,377,003 | | | **3,763** | 425 | 2,412 | **2,837** | 926 | 25% |
| Niger | 238,548 | | 1,328 | **1,328** | 169 | 802 | **971** | 357 | 27% |
| Rwanda | 366,106 | | | **1,345** | 145 | 832 | **977** | 368 | 27% |
| São Tomé and Príncipe | 35,169 | | | **317** | 111 | 118 | **229** | 88 | 28% |
| Uganda | 667,483 | | 2,047 | **2,047** | 178 | 1,169 | **1,347** | 700 | 34% |
| Cameroon | 951,496 | | | **3,587** | 643 | 1,667 | **2,310** | 1,277 | 36% |
| Ghana | 2,612,007 | | 7,350 | **7,350** | 325 | 4,576 | **4,901** | 2,774 | 38% |
| Seychelles | 35,234 | | | **513** | 186 | 118 | **304** | 209 | 41% |
| Côte d'Ivoire | 1,315,837 | | | **4,260** | 216 | 2,305 | **2,521** | 1,739 | 41% |
| Tanzania | 1,473,217 | | | **6,328** | 1,053 | 2,581 | **3,634** | 2,694 | 43% |
| Botswana | 343,050 | 471 | 1,451 | **1,922** | 300 | 780 | **1,079** | 843 | 44% |
| Mauritania | 177,806 | | | **1,976** | 492 | 598 | **1,090** | 886 | 45% |
| Kenya | 3,611,904 | 2,407 | 10,845 | **13,252** | 831 | 6,328 | **7,158** | 6,094 | 46% |
| Burundi | 86,446 | | | **892** | 189 | 291 | **480** | 412 | 46% |
| Central African Republic | 23,550 | | | **531** | 205 | 79 | **284** | 247 | 46% |
| Guinea | 270,249 | | | **1,792** | 307 | 614 | **921** | 871 | 49% |
| Liberia | 25,993 | | | **309** | 68 | 87 | **155** | 154 | 50% |
| Comoros | 44,400 | 109 | 467 | **576** | 130 | 149 | **279** | 297 | 52% |
| Madagascar | 480,369 | | | **5,691** | 1,483 | 1,092 | **2,575** | 3,116 | 55% |
| Gambia, The | 131,368 | 340 | 1,126 | **1,466** | 181 | 442 | **623** | 843 | 58% |
| Congo, Rep. | 205,000 | | | **2,279** | 155 | 689 | **844** | 1,435 | 63% |
| Ethiopia | 1,936,244 | | | **11,839** | 885 | 3,392 | **4,277** | 7,562 | 64% |
| Malawi | 274,005 | 592 | 1,881 | **2,473** | 232 | 623 | **855** | 1,618 | 65% |
| South Africa | 5,477,602 | | | **41,787** | 4,648 | 9,596 | **14,244** | 27,543 | 66% |
| Zimbabwe | 601,609 | 1,593 | 4,477 | **6,070** | 629 | 1,367 | **1,996** | 4,074 | 67% |
| Zambia | 662,526 | | | **6,771** | 432 | 1,506 | **1,937** | 4,834 | 71% |

*Source*: World Bank staff calculations based on utility annual reports and financial statements.
*Note*: Data for Ghana are available for T&D only.

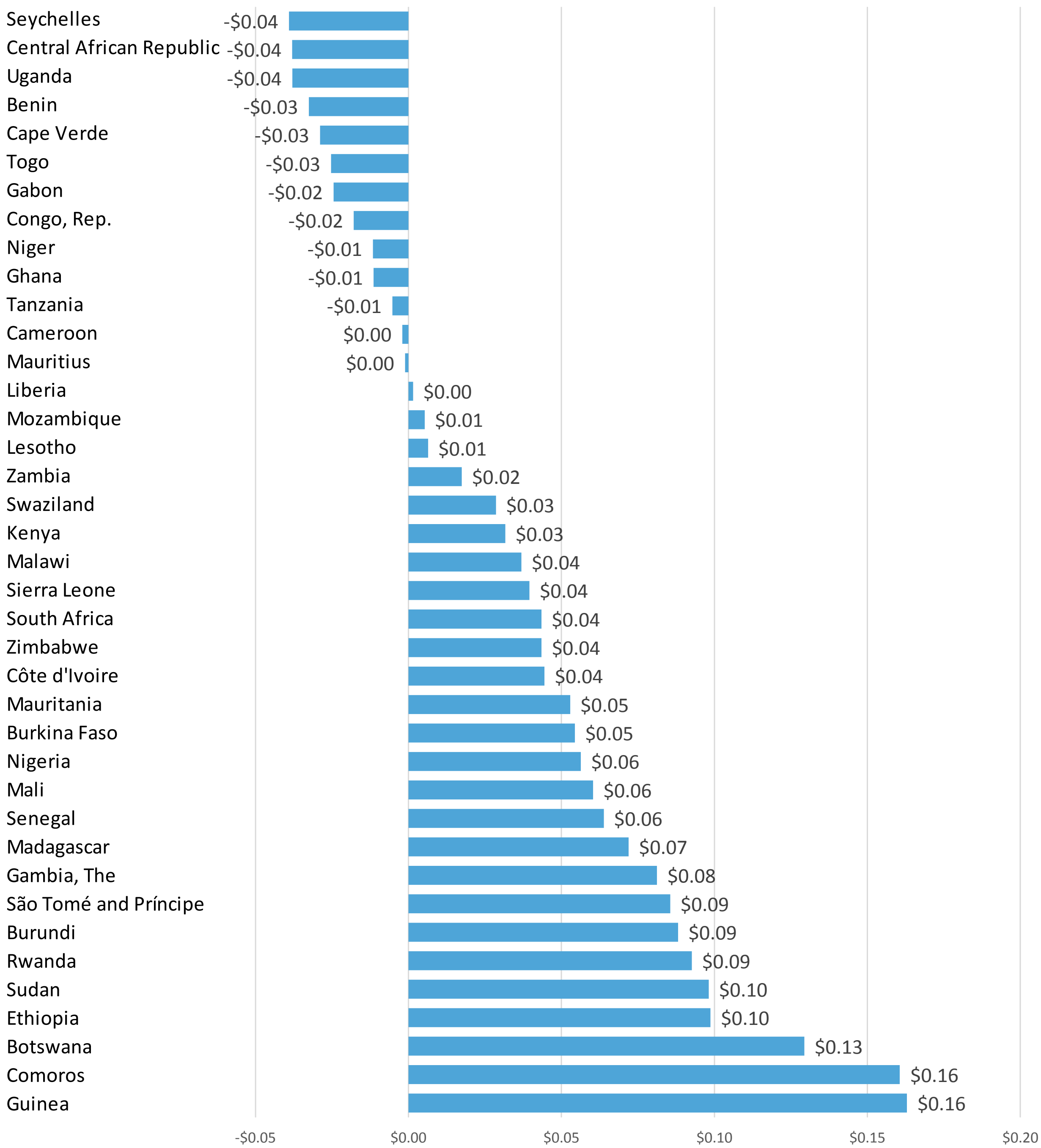
These levels of overstaffing are consistent with efficiencies gained during the reforms of utilities in Latin America in the 1990s, where efficiency gains were typically in the range of 30 to 50 percent, including the following:

- **Chile** reduced staff by 30 percent over six years despite massive system expansion (Rudnick 1996), more than doubling the number of customers per employee over a ten-year period.
- **Brazil** reduced staff by 30 percent in distribution utilities over four years despite significant system expansion, resulting in a doubling of customers per employee (USAID 2002).
- **Argentina** reduced staff by 28 percent between 1990 and 1993 (ILO 1999).

## 6.4 Underpricing

Underpricing analysis is presented in Figure 12. The median level of underpricing at benchmark performance is US$0.04 per kWh sold, which compares to the median tariff of $US0.15 per kWh sold. At benchmark performance, 13 countries are at or above cost recovery levels. Four countries are within US$0.02 per kWh billed, with the remaining requiring more significant tariff increases if existing cost structures are maintained. Underpricing remains most significant in Guinea, Comoros and Botswana, although this doesn't necessarily mean tariffs need to increase by the levels indicates on the chart if the power mix can be changed to reduce costs. For example, both Guinea and Botswana purchased expensive emergency power rentals in the reference year, while both have potential to reduce cost of service in the medium term. Guinea has significant hydropower potential and has several hydropower plants under development, and Botswana has the potential to access lower cost imports.

**Figure 12: Underpricing, constant 2014 US$ per kWh billed at benchmark performance**



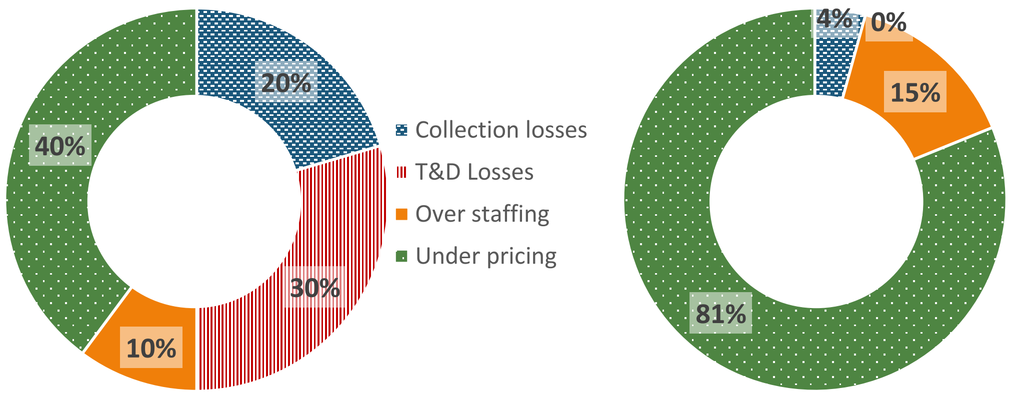

*Source*: World Bank staff calculations based on utility annual reports and financial statements.

## 6.5 Breakdown of regional quasi-fiscal deficits into hidden costs

Figure 13 presents the total hidden costs across the 39 countries. Underpricing is the dominant hidden cost. For all countries except South Africa, underpricing represents a weighted average of 40 percent of the hidden costs. T&D losses represent 30 percent of hidden costs, while bill collection inefficiencies and overstaffing represent 20 and 10 percent respectively. South Africa is treated separately because of its size and it eclipses the hidden costs in all other countries when aggregated. In South Africa, underpricing represents 81 percent of hidden costs. There are no hidden costs from T&D losses because Eskom already operates within the reference value of 10 percent. Bill collection inefficiencies are also modest at 4 percent, while the cost of overstaffing represents 15 percent of hidden costs.

**Figure 13: Breakdown of total hidden costs in SSA**

**a. All countries except South Africa** **b. South Africa**




*Source*: World Bank staff calculations based on utility financial statements, annual reports, and other documents.
*Note*: Analysis excludes only negative costs, that is, where the utility is operating at or above benchmark performance by overpricing, having lower T&D losses than benchmark, and so on.

## 6.6 Other hidden costs

As explained in section 2.3, hidden costs are measured relative to the efficient tariff at benchmark performance. It should be noted that there are several other hidden costs not captured in the analysis presented above that are difficult to quantify but could affect the QFD. Lack of financial viability could make it challenging for countries to attract IPPs without financial incentives. In a higher-risk environment, investors will tend to expect a higher return, further pushing up costs and increasing the QFD. Another example is spending on maintenance. As noted in section 2, underspending on O&M is chronic in SSA, resulting in a dilapidated and underperforming capital base, which in turn feeds higher T&D losses. Efficient levels of O&M spending would tend to increase absolute operating costs in the short term, but could result in a better-performing network, lowering T&D losses and hidden costs in the long run.

Conversely, optimizing the power mix through a least-cost power development plan could reduce costs (substantially) further. For example, as the result of poor planning, many countries rely heavily on diesel as a source of generation. In some cases diesel plants even provide baseload power when they are more suited to meet peak demand or emergency backup needs. At least five countries— Burkina Faso, Comoros, Liberia, Rwanda, and São Tomé and Príncipe—rely on diesel for more than 50 percent of electricity generated. This can represent a significant cost, especially when liquid fuel needs to be transported thousands of kilometers overland as in Rwanda and Burundi. In almost all cases, it is more cost-effective to use HFO plants which, although still expensive, have lower operating costs—on an energy basis, HFO can be 25–45 percent cheaper than diesel—and are better suited to providing base load capacity. They also have similar benefits to diesel plants, such as short installation time and the ability to switch on quickly. The current over-reliance on diesel therefore presents a short- to medium-term opportunity to reduce costs through switching from diesel to HFO.

Table 11 presents the results of a simplified analysis of potential fuel cost savings from substituting HFO for diesel in the reference year for the five countries listed above.[8] The results indicate there could be significant cost savings for those countries with a high dependence on diesel, with the QFD being reduced by 25 percent in Rwanda to as much as 63 percent in Liberia. These results are intended to be illustrative of the short term opportunity to reduce cost of generation.

**Table 11: Simplified analysis of cost savings from switching from diesel to HFO based generation**

| | % of electricity dispatched to grid generated using diesel | Potential fuel savings as % of GDP | Base-case QFD as % of GDP | Potential fuel savings as % of QFD |
|---|---|---|---|---|
| Liberia | 100% | 0.22% | 0.36% | 63% |
| Burkina Faso | 57% | 0.45% | 0.99% | 46% |
| São Tomé and Príncipe | 91% | 1.77% | 6.08% | 29% |
| Comoros | 100% | 1.10% | 4.13% | 27% |
| Rwanda | 50% | 0.26% | 1.04% | 25% |

*Source*: World Bank staff calculations based on utility data.

In the medium to long term, there are further opportunities to reduce the cost of service. While a quick and practical solution in many contexts, HFO-based generation still represents a relatively expensive source of electricity, renders countries vulnerable to international oil price shocks, and has relatively high negative environmental externalities. Where alternative domestic sources of energy are not available, power trade can open opportunities for accessing lower-cost, clean and reliable power. For example, the OMVG interconnection (*Organisation pour la Mise en Valeur du fleuve Gambie,* The Gambia River Basin Organization) in West Africa will allow Senegal, The Gambia and Guinea Bissau to access power imports from hydropower in Guinea at a fraction of the cost of HFO- and diesel-based generation, which dominates the existing power mix in those countries. Likewise São Tomé and Príncipe is preparing to rehabilitate a dilapidated hydro plant.

[8] For the purposes of this simplified analysis, it is assumed that 5 percent of the diesel consumed would still be used, for example, in the process of warming up engines from sitting idle. Heat rates of 9.81 and 11.13 gigajoules per megawatt-hour are assumed for HFO and diesel, respectively. Fuel prices in the reference year are used (Table 12).

# 7 Trend analysis

This section presents results for which QFDs are estimated under current performance where data are available for two or more years. Multiyear trend analysis helps to check the robustness of the results—for example, to see if the reference year could have been an outlier—and identify trends within the data collected. In addition, where the AICD data are available, it is informative to compare results and assess longer-term trends. Although methods used are not strictly comparable between the two studies, significant changes are likely to indicate changes in QFD patterns.

## 7.1 Robustness of results in reference year

Multiyear data are available for 31 countries, and three or more years of data available for 23 countries. Detailed results are provided in annex 8. Data are sufficient to estimate the QFD under current performance. Conducting analysis under benchmark performance and breakdown of hidden costs for all years is beyond the scope of the paper.

As illustrated in annex 8, in general QFD estimates are relatively steady from year to year. For countries with three or more years of data, the pattern is generally consistent (improving, worsening, or remaining steady). Most of the countries with low QFDs are also improving over time, while most of the countries with high QFDs are steadily high. These patterns of change are broadly consistent whether QFDs are measured relative to GDP or revenue (Kenya and Tanzania are slightly different, reflecting different growth rates in GDP and utility revenue).

Several significant increases in QFD are noteworthy:

- In **Botswana**, the QFD increased significantly in 2012, following the commissioning of Morupule B coal plant, increasing capex. Further, major capacity constraints with the new plant forced the government of Botswana to rent short-term emergency power, increasing overall costs significantly and driving up the QFD.
- In **Malawi**, the QFD increased in 2013, in part due to the commissioning of a new 50-MW hydropower plant, and in part due to large increases in distribution expenses (particularly staff costs).
- In **Sudan**, the QFD increased significantly after separation from South Sudan.

Tariff increases and improved performance helped reduce QFD in several cases:

- In the **Seychelles**, a 30-percent tariff increase was implemented in 2012, sharply reducing the QFD. A new annual tariff review system was also put in place. A quarterly adjustment of tariffs was introduced in 2014 to pass through changes in fuel prices on the world market.
- In **Tanzania**, a 40-percent tariff increase was implemented in 2014. In addition, T&D losses were reduced steadily from 25 percent in 2011 to 18 percent for the period ending June 2015.
- In **Uganda**, the QFD declined, partly driven by a 48-percent tariff increase in January 2012 following the commissioning of Bujagali, and partly driven by T&D loss reductions from 27 percent in 2012 to 21 percent in 2014.
- Finally, the QFD in **Ghana** is expected to have fallen in 2014. The reference year used in this analysis is 2013, during which time an 80-percent tariff increase was implemented in October.

Of the 17 countries that generated more than 50 percent of electricity from hydropower in the reference year, 12 have multiyear data available in this study. The QFDs in all countries with a high dependence on hydropower are either declining or steady, with no significant movements in opex from year to year. One exception may be Mozambique, where performance improvements from 2011 to 2013 were driven in part by tariff increases and in part by increased availability of hydropower over the course of the three years in our analysis, while the decline in performance in 2014 was driven by a decline in bill collection rates.

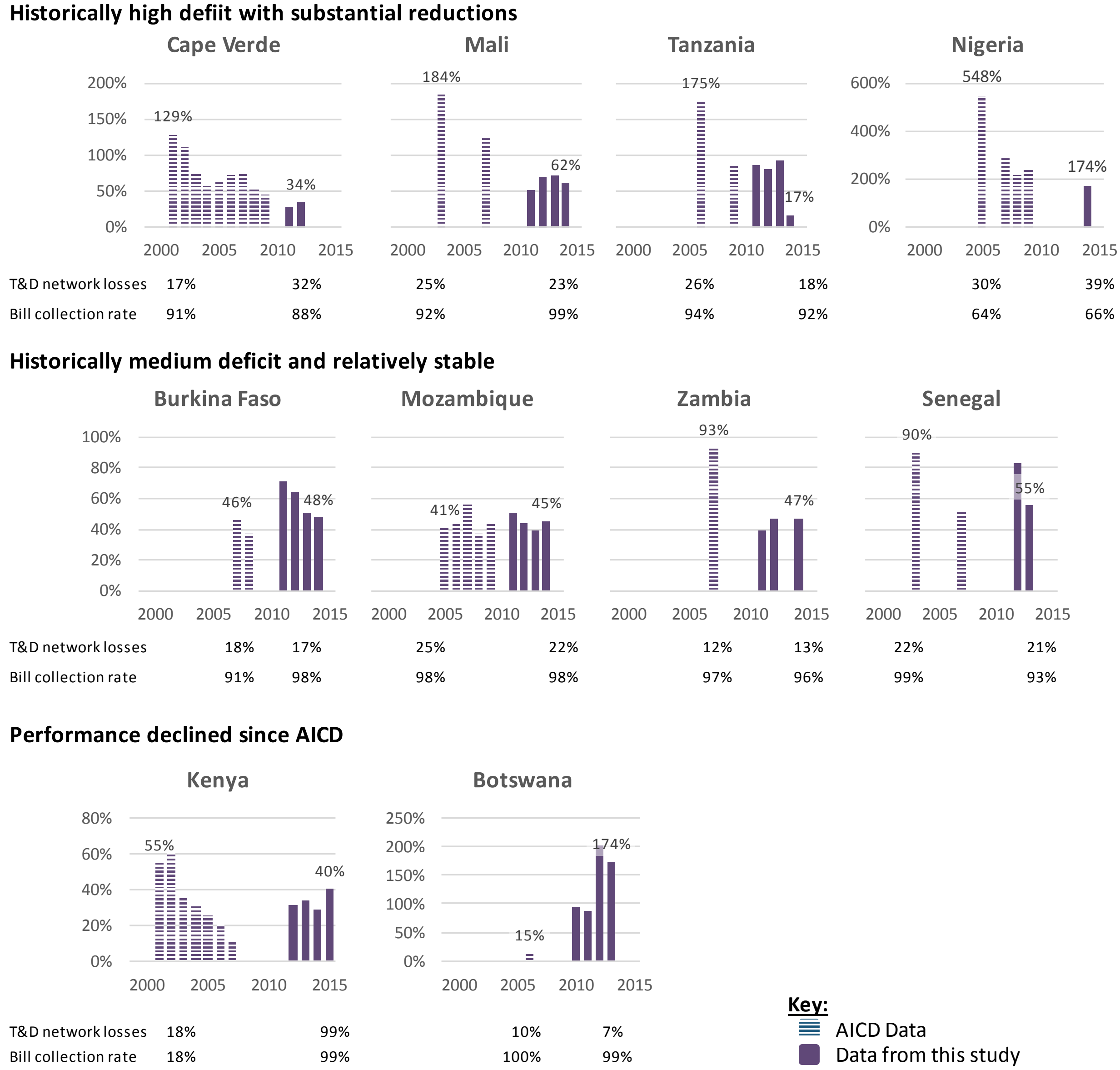
## 7.2 Comparison with AICD

AICD data are available for 18 of the countries included in the present study. As mentioned earlier, the QFD is not directly comparable due to changes in methodology outlined in annex 1.1, so the analysis presented below should be treated with caution.

Detailed data are presented in annex 8. In general, T&D losses and bill collection rates found in this study are comparable to those reported by the AICD and show a similar order of magnitude. Where losses were high in the AICD, they are also high in the present study, and where they were low, they are also low in this study. In general, the multiyear QFD results in this study are steadier than some of the significant year-to-year changes estimated by the AICD, though the AICD generally covered longer time spans than the present study. Additional observations are noted in annex 8.

Selected countries are presented in Figure 14, which identifies three groups according to their trends in QFD. T&D losses and bill collection data are also shown. Comparable cost and tariff data are not available.

**Figure 14: Trend analysis for select countries (QFD as percent of revenues)**




*Source*: AICD country reports and World Bank staff calculations.
*Note:* Where not labeled, vertical axes is on the same scale as the preceding chart. Start and end values are shown for QFD, T&D losses, and bill collection rate (full details provided in annex 8). AICD years are not specified for Botswana, Mali, Senegal, and Zambia, and years presented are assumed: 2006 for Botswana, 2003 and 2007 for both Mali and Senegal, and 2007 for Zambia. In addition to the changes in methodology, which make it difficult to compare results directly with AICD, it is unclear that T&D losses are comparable. In some cases, T&D data in AICD are referred to as "distribution losses," which are assumed here to include transmission in addition to distribution losses.

The first group of countries are those countries with historically high levels of QFD (greater than 100 percent of revenues) and that have had substantial reductions between the period observed through AICD and the period covered in the present study. As noted above, Tanzania stands out as an example following substantial tariff increases in 2014 as well as a steady reduction in T&D losses. This continues the trend of falling QFD observed in the AICD. Despite increasing T&D losses, the trend of falling QFD in Cape Verde has continued, driven by substantial tariff increases—Cape Verde has significant overpricing, as seen in Table 9. The QFD in Nigeria was very large in the AICD and remains large in the present study, but has fallen some due to steps taken in the power sector reform. As the data in annex 8 indicate, Liberia and Malawi may also fall into this group, but they are not shown in the figure because data are available for only one year and there are issues in both countries that raise questions about data accuracy.

The second group are those countries with historically medium levels of QFD (25 to 100 percent of revenues). In this group, the QFD has remained relatively stable. The third group are those countries for which the QFD has increased since the AICD period. Kenya and Botswana are notable examples. Both had close to zero QFD by the end of the AICD study period, and but medium to large QFDs in this study. For Botswana, the main driver has been the commissioning of the Morupule plant, as mentioned in section 7.1. Ethiopia may also fall into this group, where there has been major capital expansion (with significant direct support from the state, as discussed in section 5.1).

These results provide a more detailed analysis of the lack of profitability found in Dobozi (2016), which looked at a sub-sample of 16 utilities in SSA from 2000 to 2013. The paper suggests limited improvement over the 13 years covered: 13 percent of utilities reported a net profit in 2000, increasing to 30 percent in 2010 and falling to 20 percent in 2013. The results presented here are broadly consistent with this conclusion, but the data reveal positive trends in a number of countries, as well as worrying digressions in others.

# 8 Sensitivity Analyses

Sensitivity analyses check the robustness of the calculations and conclusions drawn. The recent collapse in the world price of oil is one example of what could significantly alter the findings by reducing costs in countries heavily dependent on oil-based generation. The discount rate used in annualizing capex can also be changed to test sensitivity to the cost of capital. Changing the discount rate has the same effect as changing capex at a fixed discount rate.

## 8.1 Oil product prices

Thirty-three countries generated a portion of their electricity from oil products in the reference year. During the reference years in this study, spot prices of liquid fuels spanned a wide range (Table 12). Kenya and Tanzania are the only countries for which the reference year includes the first six months of 2015 (see annex 2), which were the months following the collapse of the world oil price. The reference years for all other countries are 2010 (Lesotho), 2012, 2013, or 2014, when oil prices were high. Some generate 90 percent or more of electricity from diesel and fuel oil, and five are 100 percent dependent on oil for all their domestic electricity generation. In these countries, fuel purchases account for a high proportion of operating costs, as much as 90 percent in The Gambia. As a result, the cost of electricity generation would have fallen significantly in 2015 and may fall even further in 2016, depending on the world oil price movement.

**Table 12: Annual average spot prices of liquid fuels**

| Year | Brent<br>US$/barrel | Diesel<br>US$/liter | Heavy fuel oil<br>US$/metric tonne |
|---|---|---|---|
| 2010 | 80 | 0.56 | 427 |
| 2011 | 111 | 0.78 | 592 |
| 2012 | 112 | 0.79 | 612 |
| 2013 | 109 | 0.76 | 573 |
| 2014 | 99 | 0.70 | 507 |
| 2015 | 52 | 0.40 | 237 |

*Source*: industry sources.
*Note*: Diesel is the grade with 0.1% sulfur and fuel oil has 3.5% sulfur, and both prices are from Europe.

This sensitivity analysis assesses the hypothetical impact of the annual average oil price in 2015 prevailing in the reference year. For the purpose of this illustration, the nominal prices of diesel and fuel oil in 2015 were taken to calculate the reductions on the cost of service and the QFD in the countries with oil-based power generation by both public and private generation companies (Table 13). The starting points for fuel prices are the spot prices of US$0.40 per liter of diesel and US$237 per tonne of HFO in Table 12, to which are added shipping and transportation costs. Heat rates are consistent with those used in section 6.6. The simplified analysis assumes that shipping and land transportation costs are fixed and do not change in the short run as a result of falling world oil prices. The analysis assumes that fuel price reductions are fully passed onto utilities, which may not be the case. If, for example, fuel prices were subsidized in the reference year—through price discounts, VAT exemption, and other means—the changes in the prices charged to utilities with falling world oil prices may be smaller, as governments attempt to reduce fuel price subsidies. As such, the fuel cost savings calculated here may represent an upper bound.

**Table 13: Impacts of falling oil prices**

| Country | % of electricity generated domestically from HFO and diesel[a] | Fuel cost saving as % of current GDP | QFD as % of current GDP | Expected QFD as % of current GDP at Brent price of $52/barrel | Expected QFD as % of current GDP at benchmark performance at $52/barrel |
|---|---|---|---|---|---|
| São Tomé and Príncipe | 91% | 2.04% | 6.1% | 4.0% | -1.3% |
| Seychelles | 98% | 2.00% | -0.3% | -2.3% | -2.8% |
| Gambia, The | 100% | 1.91% | 5.8% | 3.9% | -0.6% |
| Comoros | 100% | 1.64% | 4.1% | 2.5% | -0.8% |
| Senegal | 100% | 1.50% | 2.2% | 0.7% | -0.5% |
| Cape Verde | 87% | 1.37% | 1.6% | 0.3% | -1.7% |
| Mauritius | 41% | 0.71% | 0.4% | -0.3% | -0.7% |
| Mauritania | 100% | 0.69% | 1.5% | 0.8% | -0.3% |
| Burkina Faso | 90% | 0.52% | 1.0% | 0.5% | 0.0% |
| Madagascar | 41% | 0.33% | 2.2% | 1.9% | 0.1% |
| Rwanda | 60% | 0.36% | 1.0% | 0.7% | 0.1% |
| Togo | 70% | 0.33% | 1.6% | 1.3% | -0.7% |
| Mali | 77% | 0.33% | 1.3% | 1.0% | 0.3% |
| Cameroon | 24% | 0.23% | 0.7% | 0.4% | -0.3% |
| Liberia | 100% | 0.29% | 0.4% | 0.1% | -0.3% |
| Guinea | 26% | 0.23% | 2.1% | 1.9% | 0.7% |
| Sudan | 19% | 0.18% | 1.4% | 1.2% | 1.1% |
| Tanzania | 16% | 0.20% | 0.3% | 0.1% | -0.3% |
| Burundi | 28% | 0.17% | 1.0% | 0.8% | 0.3% |
| Sierra Leone | 33% | 0.16% | 0.9% | 0.7% | -0.1% |
| Niger | 77% | 0.15% | 0.5% | 0.3% | -0.2% |
| Gabon | 8% | 0.10% | 0.4% | 0.3% | -0.3% |
| Kenya | 19% | 0.10% | 0.8% | 0.7% | 0.3% |
| South Africa | 2% | 0.07% | 3.4% | 3.4% | 2.7% |
| Botswana | 4% | 0.06% | 3.4% | 3.3% | 3.0% |
| Uganda | 4% | 0.03% | -0.1% | -0.1% | -0.4% |
| Central African Republic | 2% | 0.01% | 0.4% | 0.4% | -0.1% |
| Zambia | 0% | 0.01% | 1.2% | 1.2% | 0.8% |
| Benin | 100% | 0.01% | 0.3% | 0.3% | -0.3% |
| Ethiopia | 0% | 0.00% | 1.7% | 1.7% | 1.1% |
| Lesotho | 0% | 0.00% | 0.5% | 0.5% | 0.1% |
| Congo, Rep. | 0% | 0.00% | 0.6% | 0.6% | -0.1% |
| Mozambique | 0% | 0.00% | 0.9% | 0.9% | 0.1% |

*Source*: World Bank staff calculations.
a. Imports including purchases from regional SPVs are excluded, meaning there may not be a direct correlation between dependence on oil based generation and fuel cost savings.

The reduction in the cost of electricity service as a share of GDP in the reference year does not take into account the impact of oil price on GDP. The impact is likely to be positive in net importers and negative in net exporters heavily dependent on oil. However, two leading net exporters in SSA which would have seen a large negative effect of the low oil price on GDP—Angola and Nigeria—are not among the countries analyzed.

The results in Table 13 show that the cost savings from the drop in oil prices are expected to be greater than 1 percent of GDP in six countries (São Tomé and Príncipe, Seychelles, The Gambia, Comoros, Cape Verde, and Senegal). The price reductions would remove the QFD in Mauritius. The QFD is reduced to within 0.5 percent of GDP in Burkina Faso, Cape Verde, and Niger. If benchmark performance is assumed in addition to the 2015 annual average fuel prices, the total number of countries with below zero QFD increases from 13 to 21.

Table 14 presents the impact on countries using oil products for generation of different oil prices, ranging from US$35 to US$70 per barrel. Diesel and HFO prices corresponding to different prices of Brent were estimated by regressing historical fuel prices on Brent crude oil prices.

**Table 14: Fuel cost savings at different prices of Brent (US$/barrel), savings as percent of GDP**

| | $30 | $35 | $40 | $45 | $52 | $55 | $60 | $65 | $70 |
|---|---|---|---|---|---|---|---|---|---|
| São Tomé and Príncipe | 3.2% | 3.0% | 2.7% | 2.4% | 2.0% | 1.9% | 1.6% | 1.4% | 1.1% |
| Seychelles | 2.9% | 2.7% | 2.5% | 2.3% | 2.0% | 1.9% | 1.7% | 1.5% | 1.3% |
| Gambia, The | 3.0% | 2.8% | 2.5% | 2.3% | 1.9% | 1.8% | 1.5% | 1.3% | 1.1% |
| Cape Verde | 1.9% | 1.8% | 1.7% | 1.6% | 1.4% | 1.3% | 1.2% | 1.0% | 0.9% |
| Comoros | 2.4% | 2.2% | 2.0% | 1.9% | 1.6% | 1.6% | 1.4% | 1.2% | 1.1% |
| Senegal | 2.2% | 2.0% | 1.9% | 1.7% | 1.5% | 1.4% | 1.3% | 1.1% | 1.0% |
| Mauritius | 1.0% | 1.0% | 0.9% | 0.8% | 0.7% | 0.7% | 0.6% | 0.5% | 0.5% |
| Mauritania | 1.0% | 0.9% | 0.9% | 0.8% | 0.7% | 0.7% | 0.6% | 0.5% | 0.4% |
| Burkina Faso | 0.8% | 0.8% | 0.7% | 0.6% | 0.5% | 0.5% | 0.4% | 0.4% | 0.3% |
| Madagascar | 0.6% | 0.5% | 0.5% | 0.4% | 0.3% | 0.3% | 0.2% | 0.2% | 0.1% |
| Rwanda | 0.5% | 0.5% | 0.4% | 0.4% | 0.4% | 0.3% | 0.3% | 0.3% | 0.2% |
| Togo | 0.5% | 0.4% | 0.4% | 0.4% | 0.3% | 0.3% | 0.3% | 0.2% | 0.2% |
| Mali | 0.5% | 0.5% | 0.4% | 0.4% | 0.3% | 0.3% | 0.3% | 0.2% | 0.2% |
| Cameroon | 0.4% | 0.4% | 0.3% | 0.3% | 0.2% | 0.2% | 0.2% | 0.1% | 0.1% |
| Liberia | 0.4% | 0.4% | 0.4% | 0.3% | 0.3% | 0.3% | 0.2% | 0.2% | 0.2% |
| Guinea | 0.3% | 0.3% | 0.3% | 0.3% | 0.2% | 0.2% | 0.2% | 0.2% | 0.1% |
| Sudan | 0.3% | 0.3% | 0.2% | 0.2% | 0.2% | 0.2% | 0.1% | 0.1% | 0.1% |
| Tanzania | 0.3% | 0.3% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.1% | 0.1% |
| Burundi | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.1% | 0.1% | 0.1% |
| Sierra Leone | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.1% | 0.1% | 0.1% | 0.1% |
| Niger | 0.2% | 0.2% | 0.2% | 0.2% | 0.2% | 0.1% | 0.1% | 0.1% | 0.1% |
| Gabon | 0.2% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |
| Kenya | 0.2% | 0.2% | 0.2% | 0.1% | 0.1% | 0.1% | 0.1% | 0.0% | 0.0% |
| South Africa | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.0% | 0.0% | 0.0% |
| Botswana | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.0% | 0.0% |
| Uganda | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Central African Republic | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Zambia | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Benin | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Ethiopia | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Lesotho | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Congo, Rep. | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Mozambique | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

*Source*: World Bank staff calculations.

## 8.2 Hydrology risk

The reference year being an outlier is a particular concern in countries with a high dependency on hydropower, which are vulnerable to years of drought. In 2015 and 2016, for example, Zambia and Zimbabwe have faced significant declines in hydropower generation from the Kariba dam, due to an ongoing drought.

A marked drop in hydropower generation forces countries to seek alternative forms of electricity in the short term (such as imports or emergency power rental), or reduce electricity supply through load-shedding, or do both. As an example of the former, Aggreko in December 2015 signed a contract to provide 200 MW of short-term diesel-based power rental at Dema in Zimbabwe to offset shortages in Kariba Dam. A sudden increase in diesel power generation can in turn dramatically increase costs and therefore the QFD if tariffs are not adjusted accordingly. This sensitivity analysis looks at the impact of shortages in hydropower, assuming they are fully replaced with short-term rental power.

Twenty-nine countries generated some portion of electricity from hydropower in the reference year. This sensitivity analysis simulates the QFD impact at various reductions of hydropower availability, and replaces this lost availability with emergency power rental at an average cost of US$0.20 per kWh purchased. The analysis assumes countries do not have other spare capacity to replace the lost hydropower (as noted in section 3.4, many countries have little to no reserve margin). Actual rental costs would be country-specific. T&D losses may be lower if emergency power rental is located close to demand centers (although emergency power rental contracts in Mali and Zambia transmit power over large distances from generation sets located in Senegal and Mozambique, respectively).

Table 15 summarizes the results. In three countries, the QFD would go up five fold in the extreme case of only 50 percent hydropower availability (Zambia, Lesotho, and Ghana) and would more than triple in another two countries (Mozambique, Central African Republic and Tanzania). Effects are minor (less than 0.15 percent increase in QFD as a percent of GDP and 25 percent increase in QFD as a percent of the base-case QFD) in six countries.

**Table 15: QFD impact at various reductions in availability of hydropower plants, when replaced with emergency power at a cost of US$0.20 per kWh purchased**

| Redution in availability of hydropower plants → | Increase in QFD (% of GDP) | | | | | Base case QFD (% of GDP) | Increase in QFD (% of base-case QFD) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 10% | 20% | 30% | 40% | 50% | | 10% | 20% | 30% | 40% | 50% |
| Zambia | 1.1% | 2.1% | 3.2% | 4.2% | 5.3% | 1.2% | 87% | 173% | 260% | 346% | 433% |
| Zimbabwe | 0.9% | 1.7% | 2.6% | 3.5% | 4.3% | 5.2% | 17% | 34% | 50% | 67% | 84% |
| Malawi | 0.8% | 1.7% | 2.5% | 3.4% | 4.2% | 2.5% | 34% | 69% | 103% | 137% | 171% |
| Mozambique | 0.5% | 1.1% | 1.6% | 2.2% | 2.7% | 0.9% | 59% | 118% | 177% | 236% | 295% |
| Lesotho | 0.4% | 0.8% | 1.2% | 1.6% | 2.0% | 0.5% | 81% | 162% | 244% | 325% | 406% |
| Ghana | 0.4% | 0.7% | 1.1% | 1.5% | 1.8% | 0.5% | 80% | 160% | 240% | 321% | 401% |
| Ethiopia | 0.3% | 0.7% | 1.0% | 1.3% | 1.7% | 1.7% | 20% | 39% | 59% | 79% | 98% |
| Sudan | 0.2% | 0.5% | 0.7% | 1.0% | 1.2% | 1.4% | 17% | 34% | 52% | 69% | 86% |
| Cameroon | 0.2% | 0.4% | 0.7% | 0.9% | 1.1% | 0.7% | 33% | 67% | 100% | 133% | 166% |
| Uganda | 0.2% | 0.4% | 0.7% | 0.9% | 1.1% | -0.1% | -297% | -594% | -891% | -1188% | -1486% |
| Madagascar | 0.2% | 0.3% | 0.5% | 0.7% | 0.9% | 2.2% | 8% | 15% | 23% | 31% | 39% |
| Central African Republic | 0.2% | 0.3% | 0.5% | 0.6% | 0.8% | 0.4% | 40% | 81% | 121% | 161% | 202% |
| Guinea | 0.2% | 0.3% | 0.5% | 0.6% | 0.8% | 2.1% | 7% | 15% | 22% | 30% | 37% |
| Congo, Rep. | 0.1% | 0.3% | 0.4% | 0.6% | 0.7% | 0.6% | 26% | 52% | 78% | 104% | 130% |
| Tanzania | 0.1% | 0.2% | 0.3% | 0.5% | 0.6% | 0.3% | 41% | 82% | 122% | 163% | 204% |
| Swaziland | 0.1% | 0.2% | 0.3% | 0.4% | 0.6% | 1.2% | 9% | 18% | 27% | 36% | 44% |
| Côte d'Ivoire | 0.1% | 0.2% | 0.3% | 0.4% | 0.5% | 1.9% | 6% | 11% | 17% | 23% | 29% |
| Kenya | 0.1% | 0.2% | 0.3% | 0.4% | 0.5% | 0.8% | 14% | 27% | 41% | 55% | 68% |
| Gabon | 0.1% | 0.2% | 0.3% | 0.3% | 0.4% | 0.4% | 24% | 48% | 72% | 96% | 121% |
| Burundi | 0.1% | 0.2% | 0.2% | 0.3% | 0.4% | 1.0% | 8% | 17% | 25% | 33% | 42% |
| Sierra Leone | 0.1% | 0.1% | 0.2% | 0.3% | 0.3% | 0.9% | 8% | 16% | 23% | 31% | 39% |
| São Tomé and Príncipe | 0.0% | 0.1% | 0.1% | 0.2% | 0.2% | 6.1% | 1% | 2% | 2% | 3% | 4% |
| Rwanda | 0.0% | 0.1% | 0.1% | 0.2% | 0.2% | 1.0% | 4% | 8% | 12% | 16% | 20% |
| Mali | 0.0% | 0.1% | 0.1% | 0.1% | 0.1% | 1.3% | 2% | 4% | 7% | 9% | 11% |
| Nigeria | 0.0% | 0.0% | 0.1% | 0.1% | 0.1% | 0.5% | 5% | 9% | 14% | 18% | 23% |
| South Africa | 0.0% | 0.0% | 0.1% | 0.1% | 0.1% | 3.4% | 1% | 1% | 2% | 3% | 3% |
| Mauritius | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 0.4% | 4% | 7% | 11% | 15% | 19% |
| Burkina Faso | 0.0% | 0.0% | 0.0% | 0.1% | 0.1% | 1.0% | 1% | 3% | 4% | 6% | 7% |
| Togo | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.6% | 0% | 0% | 0% | 0% | 1% |
| ***Median*** | ***0.1%*** | ***0.2%*** | ***0.3%*** | ***0.5%*** | ***0.6%*** | | ***8.9%*** | ***17.8%*** | ***26.6%*** | ***35.5%*** | ***44.4%*** |

*Source*: World Bank staff calculations.

## 8.3 Exchange rate risk

Exchange rates directly affect costs in foreign denominated currency such as debt payments and spare parts. They also affect fuel purchases where fuel prices follow world prices. In the period 2010 to 2015, nearly all countries in the sample depreciated against the U.S. dollar, with the exception of Liberia and Zimbabwe, which use the U.S. dollar as currency (for official transaction in the case of Zimbabwe). The median depreciation was 19 percent, while three countries depreciated more than 100 percent: Sudan (155 percent), Ghana (164 percent), and Malawi (200 percent). Some countries have kept their exchange rates artificially high, such as Nigeria, which is evident in the divergence between the official and parallel-market exchange rates. Currency deregulation could see sharp depreciation.

This sensitivity analysis simulates the impact of depreciation on QFD in increments of 5 percentage points from 10-percent up to a 30-percent devaluation against the dollar. This simplified analysis considers the effects on QFD of depreciation on fuel payments and capex. Fuel estimates follow the same assumptions outlined in section 8.1, with depreciation affecting only the spot prices of diesel and HFO (which are assumed to follow spot prices on the world market), but not the costs of shipping and other transportation charges or local inflation. As such, the results presented may under-estimate effects. Capex payments follow the same assumptions as in annex A1.4. It should be noted that not all fuel and capex payments will be in U.S. dollars. Increasingly, capex may be denominated in euros or in a basket of currencies.

The results are summarized in Table 16. QFDs as a percentage of GDP would increase by a median of 0.1 to 0.4 percentage points for a 10-percent to 30-percent devaluation. In the ten most affected countries, fuel expenditures are the dominant force, driving the increase in eight countries, while capex increases dominate in three (South Africa and Malawi with highly capital-intensive sectors). The median effects on the increase in QFD as a percent of the base-case QFD are of a similar magnitude to depreciation. In some cases, the base-case QFD is relatively small but the increase in QFD is relatively large (Mauritius, Lesotho and Tanzania).

**Table 16: QFD impact at various increments of devaluation against the U.S. dollar**

| Devaluation against the U.S. dollar → | Increase in QFD (% of GDP) 10% | 15% | 20% | 25% | 30% | Base case QFD (% of GDP) | Increase in QFD (% of base-case QFD) 10% | 15% | 20% | 25% | 30% |
|---|---|---|---|---|---|---|---|---|---|---|---|
| São Tomé and Príncipe | 0.6% | 1.0% | 1.3% | 1.6% | 1.9% | 6.1% | 11% | 16% | 21% | 26% | 32% |
| Gambia, The | 0.6% | 0.9% | 1.2% | 1.5% | 1.8% | 5.8% | 10% | 16% | 21% | 26% | 31% |
| Seychelles | 0.5% | 0.7% | 1.0% | 1.2% | 1.4% | -0.3% | -181% | -272% | -363% | -453% | -544% |
| Comoros | 0.4% | 0.7% | 0.9% | 1.1% | 1.3% | 4.1% | 11% | 16% | 22% | 27% | 32% |
| South Africa | 0.4% | 0.6% | 0.8% | 1.0% | 1.2% | 3.4% | 11% | 17% | 22% | 28% | 34% |
| Cape Verde | 0.4% | 0.6% | 0.8% | 0.9% | 1.1% | 1.6% | 23% | 35% | 46% | 58% | 70% |
| Senegal | 0.4% | 0.5% | 0.7% | 0.9% | 1.1% | 2.2% | 16% | 24% | 33% | 41% | 49% |
| Malawi | 0.3% | 0.5% | 0.6% | 0.8% | 0.9% | 2.5% | 12% | 18% | 24% | 31% | 37% |
| Mauritius | 0.2% | 0.3% | 0.5% | 0.6% | 0.7% | 0.4% | 54% | 81% | 108% | 135% | 163% |
| Burkina Faso | 0.2% | 0.3% | 0.4% | 0.6% | 0.7% | 1.0% | 22% | 33% | 44% | 55% | 67% |
| Botswana | 0.2% | 0.3% | 0.4% | 0.5% | 0.6% | 3.4% | 6% | 10% | 13% | 16% | 19% |
| Lesotho | 0.2% | 0.3% | 0.4% | 0.5% | 0.6% | 0.5% | 41% | 61% | 81% | 102% | 122% |
| Mauritania | 0.2% | 0.3% | 0.4% | 0.5% | 0.6% | 1.5% | 13% | 19% | 25% | 32% | 38% |
| Ethiopia | 0.2% | 0.3% | 0.4% | 0.5% | 0.6% | 1.7% | 11% | 17% | 23% | 29% | 34% |
| Madagascar | 0.2% | 0.3% | 0.4% | 0.4% | 0.5% | 2.2% | 8% | 12% | 16% | 20% | 24% |
| Sudan | 0.2% | 0.2% | 0.3% | 0.4% | 0.5% | 1.4% | 11% | 17% | 23% | 28% | 34% |
| Guinea | 0.1% | 0.2% | 0.3% | 0.4% | 0.4% | 2.1% | 7% | 11% | 14% | 18% | 21% |
| Kenya | 0.1% | 0.2% | 0.3% | 0.4% | 0.4% | 0.8% | 19% | 28% | 38% | 47% | 57% |
| Swaziland | 0.1% | 0.2% | 0.3% | 0.4% | 0.4% | 1.2% | 12% | 18% | 23% | 29% | 35% |
| Togo | 0.1% | 0.2% | 0.3% | 0.3% | 0.4% | 1.6% | 9% | 13% | 17% | 22% | 26% |
| Mozambique | 0.1% | 0.2% | 0.3% | 0.3% | 0.4% | 0.9% | 15% | 22% | 30% | 37% | 45% |
| Rwanda | 0.1% | 0.2% | 0.3% | 0.3% | 0.4% | 1.0% | 13% | 19% | 26% | 32% | 39% |
| Zambia | 0.1% | 0.2% | 0.3% | 0.3% | 0.4% | 1.2% | 10% | 16% | 21% | 26% | 31% |
| Mali | 0.1% | 0.2% | 0.3% | 0.3% | 0.4% | 1.3% | 10% | 15% | 20% | 25% | 30% |
| Cameroon | 0.1% | 0.2% | 0.3% | 0.3% | 0.4% | 0.7% | 19% | 29% | 38% | 48% | 57% |
| Burundi | 0.1% | 0.2% | 0.2% | 0.3% | 0.3% | 1.0% | 11% | 17% | 22% | 28% | 34% |
| Côte d'Ivoire | 0.1% | 0.2% | 0.2% | 0.3% | 0.3% | 1.9% | 5% | 8% | 11% | 13% | 16% |
| Sierra Leone | 0.1% | 0.1% | 0.2% | 0.2% | 0.3% | 0.9% | 11% | 16% | 22% | 27% | 32% |
| Tanzania | 0.1% | 0.1% | 0.2% | 0.2% | 0.3% | 0.3% | 33% | 49% | 65% | 81% | 98% |
| Gabon | 0.1% | 0.1% | 0.2% | 0.2% | 0.2% | 0.4% | 22% | 33% | 44% | 55% | 66% |
| Congo, Rep. | 0.1% | 0.1% | 0.1% | 0.2% | 0.2% | 0.6% | 13% | 20% | 27% | 33% | 40% |
| Niger | 0.1% | 0.1% | 0.1% | 0.2% | 0.2% | 0.5% | 15% | 23% | 30% | 38% | 46% |
| Ghana | 0.1% | 0.1% | 0.1% | 0.1% | 0.2% | 0.5% | 12% | 18% | 24% | 30% | 36% |
| Benin | 0.1% | 0.1% | 0.1% | 0.1% | 0.2% | 0.3% | 18% | 28% | 37% | 46% | 55% |
| Central African Republic | 0.0% | 0.1% | 0.1% | 0.1% | 0.1% | 0.4% | 12% | 18% | 24% | 29% | 35% |
| Uganda | 0.0% | 0.1% | 0.1% | 0.1% | 0.1% | -0.1% | -47% | -71% | -95% | -118% | -142% |
| Nigeria | 0.0% | 0.0% | 0.1% | 0.1% | 0.1% | 0.5% | 6% | 8% | 11% | 14% | 17% |
| Zimbabwe | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 5.2% | 0% | 0% | 0% | 0% | 0% |
| Liberia | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.4% | 0% | 0% | 0% | 0% | 0% |
| ***Median*** | ***0.1%*** | ***0.2%*** | ***0.3%*** | ***0.3%*** | ***0.4%*** | | ***11.4%*** | ***17.1%*** | ***22.8%*** | ***28.5%*** | ***34.2%*** |

*Source*: World Bank staff calculations.

## 8.4 Discount rate

Capex forms a significant portion of total costs of electricity supply, especially in countries with a high dependence on such capital-intensive generation sources as hydropower and coal. This section examines the impact of varying the discount rate from 3 percent to 14 percent on the QFDs (Table 17).

**Table 17: QFD at different real discount rates (% of current GDP)**

| | **3%** | **6%** | **8%** | **10%** | **12%** | **14%** |
|---|---|---|---|---|---|---|
| Benin | 0.00 | 0.11 | 0.20 | **0.28** | 0.37 | 0.46 |
| Botswana | 2.18 | 2.65 | 2.99 | **3.35** | 3.73 | 4.10 |

| | 3% | 6% | 8% | 10% | 12% | 14% |
|---|---|---|---|---|---|---|
| Burkina Faso | 0.43 | 0.66 | 0.82 | **0.99** | 1.17 | 1.35 |
| Burundi | 0.57 | 0.72 | 0.83 | **0.95** | 1.08 | 1.20 |
| Cameroon | 0.26 | 0.42 | 0.54 | **0.67** | 0.80 | 0.93 |
| Cape Verde | 0.85 | 1.16 | 1.39 | **1.63** | 1.87 | 2.12 |
| Central African Republic | 0.12 | 0.23 | 0.31 | **0.39** | 0.48 | 0.56 |
| Comoros | 3.47 | 3.73 | 3.93 | **4.13** | 4.34 | 4.55 |
| Congo, Rep. | 0.11 | 0.29 | 0.42 | **0.56** | 0.70 | 0.84 |
| Côte d’Ivoire | 1.34 | 1.57 | 1.74 | **1.92** | 2.10 | 2.28 |
| Ethiopia | 0.58 | 1.02 | 1.35 | **1.69** | 2.04 | 2.40 |
| Gabon | 0.03 | 0.16 | 0.26 | **0.36** | 0.47 | 0.58 |
| Gambia, The | 4.50 | 5.04 | 5.42 | **5.83** | 6.25 | 6.68 |
| Ghana | 0.12 | 0.26 | 0.35 | **0.45** | 0.56 | 0.66 |
| Guinea | 1.50 | 1.74 | 1.91 | **2.10** | 2.29 | 2.48 |
| Kenya | 0.20 | 0.43 | 0.60 | **0.78** | 0.97 | 1.16 |
| Lesotho | -0.69 | -0.22 | 0.13 | **0.49** | 0.86 | 1.23 |
| Liberia | 0.24 | 0.29 | 0.32 | **0.36** | 0.39 | 0.43 |
| Madagascar | 1.69 | 1.90 | 2.05 | **2.21** | 2.38 | 2.54 |
| Malawi | 0.77 | 1.45 | 1.95 | **2.48** | 3.02 | 3.58 |
| Mali | 0.94 | 1.08 | 1.18 | **1.29** | 1.40 | 1.51 |
| Mauritania | 1.12 | 1.28 | 1.40 | **1.52** | 1.65 | 1.78 |
| Mauritius | -0.23 | 0.04 | 0.23 | **0.43** | 0.64 | 0.85 |
| Mozambique | 0.17 | 0.47 | 0.69 | **0.92** | 1.16 | 1.39 |
| Niger | 0.26 | 0.35 | 0.41 | **0.48** | 0.54 | 0.61 |
| Nigeria | 0.36 | 0.43 | 0.48 | **0.54** | 0.59 | 0.65 |
| Rwanda | 0.74 | 0.86 | 0.95 | **1.04** | 1.13 | 1.23 |
| São Tomé and Príncipe | 5.15 | 5.52 | 5.80 | **6.08** | 6.37 | 6.66 |
| Senegal | 1.69 | 1.89 | 2.03 | **2.18** | 2.33 | 2.48 |
| Seychelles | -0.94 | -0.67 | -0.47 | **-0.26** | -0.05 | 0.18 |
| Sierra Leone | 0.49 | 0.64 | 0.75 | **0.87** | 0.99 | 1.11 |
| South Africa | 1.36 | 2.17 | 2.78 | **3.43** | 4.10 | 4.78 |
| Sudan | 0.68 | 0.97 | 1.19 | **1.41** | 1.64 | 1.88 |
| Swaziland | 0.38 | 0.73 | 0.98 | **1.24** | 1.51 | 1.78 |
| Tanzania | -0.02 | 0.10 | 0.19 | **0.28** | 0.38 | 0.47 |
| Togo | 1.13 | 1.32 | 1.46 | **1.60** | 1.75 | 1.90 |
| Uganda | -0.23 | -0.17 | -0.12 | **-0.07** | -0.03 | 0.02 |
| Zambia | 0.49 | 0.79 | 1.00 | **1.23** | 1.45 | 1.69 |
| Zimbabwe | 2.08 | 3.32 | 4.23 | **5.19** | 6.17 | 7.17 |
| | | | | | | |
| Maximum | 5.15 | 5.52 | 5.80 | **6.08** | 6.37 | 7.17 |
| Minimum | -0.94 | -0.67 | -0.47 | **-0.26** | -0.05 | 0.02 |
| Median | 0.49 | 0.73 | 0.95 | **1.04** | 1.17 | 1.39 |

*Source*: World Bank staff calculations

The discount rate in this study represents the cost of capital. Aside from limited concessional financing provided by international organizations, most utilities in SSA are not able to obtain loans with long tenor. A discount rate of 6 percent is tested to represent the lowest estimated cost of capital in real terms the highest-performing utilities could access. Reducing the discount rate to 6 percent is equivalent to reducing capex by about 35 percent (depending on the number of years over which capex is amortized) at the base discount rate of 10 percent, and conversely increasing the rate to 14 percent is equivalent to increasing capex by about 40 percent. A lower bound of 3 percent is intended to represent concessional financing as well as net-of-inflation government bond rates in some countries, such as South Africa. An upper bound real discount rate of 14 percent is tested to represent highest-risk contexts.

Because the discount rate is used only to annualize capex in this study, the impact of changing the discount rate rises with increasing proportion of total supply costs spent on capex. Because power purchases from IPPs were taken as opex and the embedded capex in generation was not separately accounted for, the results in Table 17 should be interpreted with caution. The countries with high proportions of power purchase are Guinea and Uganda.

Among those countries with high capex as a share of the total supply cost, Ethiopia has the highest proportion, with capex comprising more than 90 percent of the estimated total cost of service (see discussion in section 5.1). The cost of service in the base case of 10 percent is US$0.17 per kWh billed, falling to US$0.08 at 3 percent and as high as US$0.23 at 14 percent. The QFD as a portion of GDP in South Africa is highly sensitive to the discount rate used. In the base case the QFD is equivalent to 3.4 percent of GDP, falling to 1.4 percent of GDP when a discount rate of 3 percent is used.

# 9 Conclusions

More than 600 million people in SSA do not have electricity. Those who are connected to the grid face frequent power outages, some daily. Many pay high tariffs—by international standards—for poor service quality. Substantial capital injections are needed to meet growing demand, improve service quality, and increase operational efficiency to reduce costs of supply. To do so, the financial viability of electricity sectors is critical. Without financial viability, it is difficult for utilities to operate efficiently or expand their reach. In the face of financial shortfalls, utilities are forced to cut O&M spending, starting a vicious downward spiral of asset degradation, declining operational efficiency, and deteriorating service quality.

Mozambique provides a case in point. The electricity sector is not free of QFD, but its revenues cover opex fully, which puts Mozambique in better financial shape than many other countries in the region. But the access rate in Mozambique is only 20 percent. Even just to meet targets that are much more modest than universal access, the sector is estimated to require an additional half a billion dollars or more a year (World Bank 2015b). A dominant aspect of the operational reality of utilities like Electricidade de Moçambique (EdM) is that they are already facing higher costs. In recent years, EdM has been funding significant numbers of new connections at the expense of operations, maintenance, and, ultimately, service quality. Expanding access calls for a significant scale-up in capex as well as planning, costing, and budgeting activities, and strengthening staff technical capacity, management capacity, and focus.

A lack of financial viability increases costs in other ways. With public capital in scarce supply, private capital is sorely needed. However, attracting private investors becomes very costly. First, fewer companies will be willing to invest, thereby reducing competition, including price competition. Faced with uncertainties, investors and financiers will require higher rates of return and guarantees from governments and donors to compensate for the higher risks.

As a result of financial gaps, utilities have fallen deeper into debt, prompting governments to provide utilities with subsidies, which are increasingly unsustainable. Justifications for subsidies range from reducing the cost of electricity for economic growth and competitiveness to curbing inflation and making electricity affordable to households. In SSA, where only one-third of the population has access to electricity and many without access are low-income households, there is a compelling case for targeted assistance to help increase the rate of access and meet the basic energy needs of the poor. But subsidies that cover the costs of operational inefficiencies decrease utilities' incentives to improve their performance. Untargeted subsidies grow disproportionately large relative to available government resources, competing for limited resources that could otherwise be used to deliver other essential services. And producers are seldom, if ever, fully and immediately reimbursed for subsidies, further threatening the financial viability of utilities.

**What is the status of the financial viability of electricity sectors in SSA? What is the magnitude of electricity sector QFDs in SSA?**

Using the base-case definition adopted (level four on the ladder of financial viability), this paper finds that only two countries in SSA have financially viable electricity sector (the Seychelles and Uganda). This means utilities may not be able to sustain existing asset bases without government subsidies, let alone consider capacity expansion. A further 18 countries cover opex but do not collect sufficient revenues to cover capex on the new replacement value of existing assets (level two on the financial viability ladder). Six countries have financial losses in excess of US$0.20 per kWh billed of which two are in excess of US$0.30/kWh (Comoros and São Tomé and Príncipe).

These financial losses translate into QFDs of 1.5 percent of GDP on average, and more than 5 percent of GDP in The Gambia, São Tomé and Príncipe, and Zimbabwe. QFDs represent a fiscal burden on the government through direct subsidy transfers, capital investments, bailouts, tax breaks, and other means. The QFD in South Africa stands out in the region, accounting for almost US$11 billion per year. Indeed the national utility Eskom has been severely financially strained in recent years, driven by a dilapidated and aging generation fleet, delays in new capacity coming online, and repeated requests for tariff increases being only partially met by the regulator. The persistent revenue-expenditure gap has led to several bailouts from the government, including debt forgiveness in the form of the Subordinated Loan Special Appropriation Amendment Bill passed by the South African parliament in June 2015, converting the 60-billion-rand loan granted in 2008 (worth US$7.3 billion at the time) to the national power utility Eskom to equity. The QFD in Ethiopia is dominated by capex costs that reflect the major capital expansion undertaken by the government over the last 15 years. As Ethiopia tries to position itself strategically as a supplier of low-cost and clean energy in the sub-region, the government has financed significant increases in hydropower capacity and associated T&D infrastructure.

There may be valid reasons for large QFDs, such as state funding for capital expansion programs as in Ethiopia. It is important for such expenditures to be deliberate and transparent. Where this is not the case, “hidden” costs and thus the “hidden” (but quite real) contingent fiscal liabilities can become a problem because these are not sufficiently openly and explicitly presented for policy debates and decisions. In addition to the large fiscal burden that QFDs may impose, another consequence of large QFDs is an undercapitalized sector in a state of disrepair. Frequent blackouts that result force businesses to rely on expensive diesel generators and factories to shut down, with serious negative macroeconomic consequences. South Africa is a good illustration, with rolling blackouts taking a toll on the economy and harming economic growth. The adverse macroeconomic effects of power outages are discussed in Bacon and Kojima (2016, chapter 4).

The data set built through this study provides a view on long-term trends through comparison with AICD results. Substantial improvements are apparent in several countries. QFDs in Tanzania fell sharply in 2014 following tariff increases, helped further by a steady reduction in T&D losses. The QFD in Nigeria was very large in the AICD and remains large in the present study but has fallen following privatization and continuing power sector reforms. On the other hand, some countries appear to have slipped in the financial performance of the sector. Botswana is one example where the QFD was almost zero in the AICD, but has increased due to delays in the commissioning of new power plants, forcing reliance on emergency power rentals.

The results in this paper are sensitive to oil prices and hydrology risk. One concern is whether the reference year could have been an outlier—for example whether the reference year was a year of abundant rainfall or severe drought in a country that depends significantly on hydropower. For the 23 countries with three or more years of data available, the multiyear analysis suggests that the reference years selected for each country do not appear to be outliers.

**What are the priority areas in individual countries for reducing costs and increasing cost recovery?**

The hidden-cost analysis presented in this paper helps identify what policy responses might be most effective in each context. To close the financial gap in the sector, tariff increases are often the principal option considered, yet this study shows that policy makers have a range of options to increase revenues and reduce costs.

T&D and collection losses combined account for half of the estimated hidden costs, more than underpricing, which accounts for 40 percent. They represent the dominant hidden cost in 18 countries. When utilities are operating at benchmark performance of 10-percent T&D losses, 100-percent bill collection rates, and staffing at benchmark levels, the QFD is reduced to below zero in a further 11 countries bringing the total to 13, indicating that current tariffs might be sufficient to cover costs over the medium term. In these cases, it may make sense for policy makers to focus more on cost reductions and increased cash collections to close the financial gap than on tariff increases. International experience suggests that unmetered consumption is disproportionately concentrated in large consumers and others who are able to pay cost-reflective tariffs. By targeting better-off, large-volume customers first, significant loss reduction is possible with little loss of welfare. That said, even in countries where benchmark performance could eliminate QFDs, tariff increases may not be entirely avoidable because T&D and collection losses cannot be eliminated at zero cost. Tariffs should aim to cover prudently and reasonably incurred operating, maintenance, and capital costs.

Achieving these loss reductions would require time and investment. Antmann (2009) describes how to reduce T&D and collection losses sustainably with examples from developing countries. T&D losses can often be reduced through relatively simple short- and medium-term investments to address technical losses (e.g., T&D network upgrades to address system bottlenecks) and non-technical losses (e.g., smart meters to detect meter tampering, or replacing old meters that are out of calibration and beyond repair). Smart meters enable remote readings which can reduce the need for staff to perform meter readings. Utilities may benefit from business management platform upgrades, including customer management software to help monitor and identify points in the network where losses are abnormal. Programs to encourage switches from credit to pre-paid meters can help increase bill collection rates. A specific cost estimate on the investments needed is a country-specific exercise beyond the scope of this study.

With no changes in power mix or other cost saving measures, tariffs would need to increase by a median value of US$0.10 per kWh billed at current sector performance and US$0.04 per kWh billed at benchmark performance, representing a 62-percent and 24-percent increase on current average tariffs, respectively. The multiyear analysis presented in this paper illustrates the impact policy reform has had in some countries. For example, tariff increases of 48 percent and 30 percent, respectively, in Uganda and the Seychelles helped these countries come closest to financial viability among the 39 countries analyzed.

In considering how best to reduce QFDs, sequencing is important. Experience from other countries demonstrates that tariff increases are possible, but the quality of service needs to improve before tariff increases are broadly accepted. The quality of service is not measured in a systematic way in most countries. Indicative evidence collected in this study suggests that serious problems with quality of supply persist in SSA, with regular interruptions to the supply of electricity often for prolonged periods of time. It is equally important that price increases be targeted to those customers who can afford tariff increases. Generally speaking, low-consumption residential customers have a lower ability to pay while high-consumption-residential, commercial, and industry customers have a greater ability to pay. In addition, low-consumption residential customers represent a very small share of utility sales. In principle, therefore, tariff increases could be focused on customers with a greater ability to pay, making it more politically feasible to implement tariff increases. Although political sensitivity of tariff increases to users in these segments cannot be ignored, it should also not be overestimated. Successful examples of reforms of power sector in emerging countries in other regions (Latin America, Europe, and Central Asia) show that high- and middle-income users in all tariff categories usually accept to pay cost-reflective rates, provided they receive a service of good quality.

The price increase required may be lower if the power mix can be optimized on a least-cost basis. An opportunity for cost reduction in the short to medium term for countries using diesel for base load generation is to switch to HFO. Many countries in West Africa rely heavily on diesel-based generation for base load capacity. A clear trend in recent years has been an increasing dependence on short-term rental power, which typically uses diesel. Basic analysis of countries heavily dependent on diesel-based generation in this paper shows that QFDs could be reduced by 25 to 65 percent through fuel savings alone by switching to HFO. In the medium to long term, other significant opportunities exist to reduce the cost of generation. Recent major gas discoveries of the east coast (e.g., Mozambique and Tanzania) and the west coast (e.g., Senegal and Mauritania) could enable new power generation from natural gas. Developing the region's untapped hydropower potential can also open the opportunity for power trade to access this low-cost, clean source of energy. An example is the OMVG interconnection project in West Africa, which will enable Guinea to develop and export hydropower.

The hidden cost of overstaffing represents a small portion of the QFD in general but is an area of concern in some countries. While median overstaffing across all utilities is 41 percent, staff costs generally represent a small share of opex. It is important to note that there are at least several important dimensions to consider with respect to utility staffing, including staff numbers, skill set, attendance (reporting to work), and salary. This study assumes adjusting to optimal staffing levels would entail a part reduction in staff numbers and a part increase in salary levels to attract staff with greater skills. Applying these assumptions even in the most extreme case of Zambia with 70 percent overstaffing, the additional cost of overstaffing represents only 18 percent of the QFD.

Oil price reduction in 2015 is expected to have reduced the QFD substantially in countries with a high dependence on petroleum products for electricity generation. The price reductions would remove the QFD in Mauritius, and bring to within 0.3 percent of GDP in Cape Verde, Liberia, and Tanzania. Combining low oil prices with benchmark performance would bring the total countries with no QFD to 21. To avoid escalating QFD in the future in the event of oil price shocks, an important policy consideration for these countries is to implement automatic fuel price pass-through mechanisms as part of the tariff structure, similar to those introduced in Kenya and the Seychelles.

# Annex 1: Notes on methodology

This annex provides detailed notes to the methodology described in section 2.

## A1.1 Methodology used in the AICD

The AICD estimated the overall annual costs of underpricing, T&D losses, collection losses, and overstaffing as follows:

$$Underpricing = kWh\ billed \times (unit\ historical\ cost - overstaffing - \ efficient\ average\ tariff);$$

$$T\&D\ losses = kWh\ billed \times unit\ historical\ cost \times (\%loss - 10\%)/(100\% - 10\%)\ ;$$

$$Collection\ losses = kWh\ billed \times effective\ average\ tariff \times (100\% - \%\ bill\ collection);\ \text{and}$$

$$Overstaffing = \{413 - (no.\ of\ customers\ per\ employee)\}/413 \times annual\ salary\ bill\ ,$$

where 413 is the benchmark number of customers per employee in developing countries. The results obtained were then divided by utilities' revenues and GDP to show their respective shares (as percent of revenue and percent of GDP).

Opex was taken from utility financial statements, while capex was calculated based on new replacement value of existing assets. This approach is used to reflect the reality that many, if not the majority, of capital investments are financed by the state, and therefore investment costs and associated debt servicing are not reflected on utility financial statements.

While the AICD carried out modeling to develop and cost a long-term expansion plan for each country with and without regional trade, the study did not use these modeling results to compute the supply cost. Instead, the AICD took the existing assets in the base year (typically 2005), and made assumptions about overnight investment costs to estimate capex. For power generation, the specific assumptions used for costs and years of economic life can be found in annex 7 of Briceño-Garmendia and Shkaratan (2011). The unit costs for coal, gas, and oil-fired power generation were the same in every country, but location-specific for hydropower. There was no distinction in capex between diesel and fuel oil generation. The capex associated with T&D consisted of two components. The first had to do with T&D infrastructure, and the second to do with connecting customers. For the latter, a simple rule of US$500 per connection was assumed, multiplied by the total number of MV and LV customers. To annualize capex, a discount rate of 10 percent was used. Unit historical costs and effective average tariffs were calculated using the formulae below:

$$\begin{aligned} &Unit\ historical\ cost \\ &\quad = \frac{\sum Overnight\ investment\ costs\ for\ power\ generation\ and\ T\&D\ annualized}{kWh\ generated} \\ &\quad + \frac{(US\$500 \times number\ of\ MV\ and\ LV\ customers)\ annualized}{kWh\ billed\ to\ medium\text{-}\ and\ low\text{-}voltage\ customers} \\ &\quad + \frac{\sum Operating\ costs\ reported\ in\ utilities'\ financial\ statements}{kWh\ generated}\ ; \end{aligned}$$

$$Effective\ average\ tariff\ \cong\ Effective\ residential\ tariff\ for\ monthly\ consumption\ of\ 100\ kWh.$$

To improve estimations, the methodology used in the present study departs from that used in the AICD:

- The AICD divided the annualized capex by kWh generated and multiplied by kWh billed to arrive at total capex. This does not yield the total benchmark capex because T&D losses are embedded in the kWh billed. In this study, the benchmark unit cost is based on 90 percent of kWh dispatched, which assumes aggregate T&D and collection losses of 10 percent.

- This study calculates the average tariff by dividing the amount billed by kWh billed. In the AICD, the average tariff is the effective residential tariff for monthly consumption of 100 kWh, which affects underpricing.
- The capex for LV distribution lines in this study is based on analysis of costs assumed for setting tariffs for the five-year period 2013–2017 in Peru—assumed to be a suitable reference country—in six prototype areas, ranging from high-density urban to low-density rural areas. The costs are increased by 25 percent to reflect higher costs in SSA.
- The AICD assumed that staff levels are entirely a function of the number of customers that distribution companies have, but such an assumption does not apply to power generation. This study instead estimates overstaffing by using benchmark employment in generation, transmission, and distribution separately. The most extensive analysis is carried out for generation, for which information on the type and size of each generation plant was collected. Efficient levels of staffing for generation were estimated based on the type and size of each generation plant. The benchmark number of employees for T&D is set by km of T&D lines with voltage greater than 1 kV and the number of customers. The total numbers of employees reported in the utilities' annual reports are compared with the staff complement in utilities in three clusters of power utilities in Latin America with similar numbers of customers and km of T&D lines. Annex A1.4 provides additional details.

## A1.2 Financial statement data

Utility financial statements were the primary source of revenues, opex, and other financial data. The study assumes utilities follow IFRS and IAS unless otherwise stated by the utility. Table A1.1 provides a description of each element and the assumptions applied.

**Table A1.1: Description of financial data collected and assumptions applied**

| Element | Description and assumptions |
|---|---|
| **Revenues** | Revenues captured concern only those directly related to electricity sales that are retained by power utilities. Revenues captured cover those directly related to electricity sales, including collection of bill payments for electricity sales (tariff collection, connection, and reconnection charges), interest from consumer loans, and wheeling charges.<br>IFRS means that revenues are recorded in financial statements on an accrual basis rather than a cash-flow basis, meaning electricity revenue is recognized when electricity is billed to the user. As a result, revenues reflect the amounts billed, and not amounts of cash collected. Per IAS 18, revenue from taxes, fees, and other charges passed on to third parties, such as VAT and subscription fees for public broadcasting corporations (as in Cape Verde), are assumed to be excluded.<br>The following revenues are excluded:<br>- Revenues not directly related to electricity sales, such as revenues from sales of other goods (e.g., water, fiber optic cable leases), financial income, such as interest earned on bank balances or interest earned from non-electricity sector investments, rental income, extraordinary income such as insurance proceeds, and unidentified income ("other income", "sundry income," or "miscellaneous revenue"). |

| Element | Description and assumptions |
|---|---|
| | - Subsidies in the form of direct transfers. Direct transfers may contribute to opex that are passed through the utility such as emergency power rentals, and capex costs such as direct investment costs and associated expenditures such as implementation of environmental and social management plans. Examples include grants received from national governments (e.g., the government of Botswana transferred US$91 million to the state-owned utility in 2010 and 2011) and donors (e.g., the state-owned utility in Liberia reported grants from Norway, Global Partnership for Output-Based Assistance, and the World Bank).<br>- Impairment of receivables, and cancellation of impairments of receivables (described further below). |
| **Operation and maintenance costs** | All opex directly related to the sale of electricity are captured, including<br>- variable costs such as power purchases and consumables related to self-generation (fuel costs, water, lubricants)<br>- fixed costs (property costs, staff costs including corporate functions and salaries associated with system operations).<br>Costs not directly related to electricity sales are excluded, such as costs of providing water services and identified on financial statements as extraordinary activities. |
| **Capital costs** | All costs related to loan repayments are assumed to be entirely related to capex for assets used in the generation, transmission, and distribution of electricity and are therefore excluded from cost-of-supply estimations because capex is calculated separately based on existing assets. Payments include principle payments—which reflect the repayment of previous capital expenditures made by the utilities, typically recorded on cash flow statements—and interest payments, typically recorded on income statements. Other financing costs may include realized costs, including fair-value losses on cross-country and interest rate swaps, and other financial liability payments. Losses on currency exchange reflect a devaluation of the local currency relative to the loan currency. Depreciation costs on existing assets and property, and unrealized fair-value losses on cross-currency and interest rate swaps are also excluded.<br>Unbundled sectors require a slightly different approach. With the exception of Nigeria, the dominant state-owned distribution utility is used as the primary source of information. To capture all loan payments in the value chain, particularly for generation investments which typically constitute the major outlays, loan payments recorded in the financial statements of state-owned utilities upstream of distribution are identified and included. To avoid double counting, the cost of power purchases for the distribution company are reduced by the same amount. |

*Source*: World Bank staff.

## A1.3 Impairments, bill collection rates, and cash collected

Impairment of receivables represents non-collection of billed amounts, but the timing becomes an issue because the amounts could have been billed in the preceding financial years. For this reason, this study excludes impairment of receivables and provisions for impairments from calculations and instead uses utility-reported bill collection rates for the purpose of quantifying collection inefficiencies. When reported, bill collection rates are assumed to represent total cash collected in a given year as a proportion of total revenue billed in the same year.

Bill collection rates were not available in seven countries and assumptions had to be made. A 99-percent bill collection rate was assumed for utilities with publicly accessible audited accounts available for 2013 or later (Botswana, Gabon, Mauritius, the Seychelles, and Swaziland). An 87 percent bill collection rate was assumed for Ethiopia and Lesotho, which is the median bill collection rate for utilities on the continent. Cash collected by the utility in the reference year is assumed to be equivalent to total revenue (including tariff and non-tariff revenue) multiplied by the bill collection rate.

## A1.4 Capital cost estimates

All capital costs were annualized over the economic life of the plant ($T$) at a real discount rate ($r$) of 10 percent to yield annual capex:

$$Amortized\ capital\ cost = Overnight\ investment \times \frac{r}{1-(1+r)^{-T}}.$$

### Generation capital costs by technology

Generation capital costs were estimated using the assumptions outlined in Table A1.2 and Table A1.3. Installed capacity data used in the reference year calculations are listed in annex 4. New replacement values of generation assets were determined by technology using reference costs from various sources including case studies of 21 IPP projects in SSA from Eberhard and Gratwick (2011), the U.S. Energy Information Administration, International Renewable Energy Agency, and individual projects developed in the region for each technology. In addition, heat rates assumed in Table A1.2 were used to calculate the amount of fuel required, from which fuel expenditures were estimated.

**Table A1.2**: **Assumptions about generation parameters**

| Technology | Capex (US$/kW) | Economic life (years) | Heat rate (gigajoules/MW-hour) |
|---|---|---|---|
| Biomass | 2,500 | 30 | 14.25 |
| Coal | 2,403 | 30 | 9.29 |
| CoGen | 917 | 30 | 7.44 |
| Diesel | 1070 | 30 | 11.13 |
| Gas CC | 917 | 30 | 7.44 |
| Gas OC | 603 | 30 | 12.14 |
| Geothermal | 4,362 | 30 | n.a. |
| HFO | 1,250 | 30 | 9.81 |
| Hydropower | See below | 35 | n.a. |
| Nuclear | 4,102 | 60 | n.a. |
| Solar | 2,500 | 25 | n.a. |
| Wind | 2,000 | 25 | n.a. |

*Sources*: IEA, (U.S.) Energy Information Administration, International Renewable Energy Agency, and World Bank technical specialists.
*Note*: n.a. = not applicable.

As with the AICD, a single cost was assumed in every country for each technology irrespective of location or size, with the exception of hydropower (Table A1.3). There were more categories for technologies than in the AICD study, which had three costs in total for all generation plants using fossil fuels ("oil," coal, and gas). Plant-level data on hydropower generation capacity were obtained to estimate a weighted-average capital cost of hydropower in each country based on three capacity categories. Hydropower plants were assumed to be refurbished after 35 years at a cost of 35 percent of the cost of a new plant. The life of each existing hydropower plant was checked, and if the plant was less than 35 years old in the reference year, the capex in Table A1.3 was annualized over 35 years. If the plant was more than 35 years old, 35 percent of the cost in Table A1.3 was annualized over 35 years. The final results are shown in Table A1.4.

**Table A1.3: Hydropower parameter assumptions**

| Category | Size (MW) | Capex (US$/kW) | Refurbishment costs (% of capital costs) |
|---|---|---|---|
| Small | 0–50 | 4,000 | 35 |
| Medium | 50–400 | 2,000 | 35 |
| Large | >400 | 1,500 | 35 |

*Source*: World Bank hydropower specialists.

**Table A1.4: Country-specific hydropower parameter estimates**

| Country | Weighted average capex (US$/kW) | Country | Weighted average capex (US$/kW) |
|---|---|---|---|
| Angola | 3,143 | Mozambique | 3,500 |
| Burkina Faso | 4,000 | Namibia | 2,000 |
| Burundi | 4,000 | Nigeria | 1,500 |
| Congo, Dem. Rep. | 2,643 | Rwanda | 4,000 |
| Côte d'Ivoire | 3,000 | Sierra Leone | 4,000 |
| Ethiopia | 2,727 | Sudan | 3,071 |
| Ghana | 1,750 | Swaziland | 3,333 |
| Guinea | 3,667 | Tanzania | 2,571 |
| Kenya | 3,231 | Togo | 2,000 |
| Lesotho | 2,667 | Uganda | 2,800 |
| Malawi | 2,889 | Zambia | 2,083 |
| Mali | 3,333 | Zimbabwe | 1,500 |

*Source*: World Bank staff calculations.

## Transmission and distribution costs

T&D costs were estimated based on reported km of T&D lines, excluding LV distribution lines below 1 kV for which no reliable information is available. T&D line data used in the reference year calculations are listed in annex 4. For the purpose of these study, two costs were used: one for lines above 33 kV, and the other for lines between 1 kV and 32 kV. While the cost of building and maintaining T&D infrastructure varies significantly across countries, structure type, voltage, and terrain (desert, flatland, forest, mountains, urban versus rural), it was not possible within the scope of this study to perform a detailed T&D cost analysis in each country. Assumptions, provided by industry specialists, are summarized in Table A1.5.

**Table A1.5: Assumptions on T&D cost estimates**

| Component | Assumed value (US$/km) | Economic life (years) |
|---|---|---|
| Lines 110kV or above | 165,000 | 50 |
| Lines below 110kV down to 66kV | 65,000 | 40 |
| Lines below 66 kV down to 1 kV | 10,000 | 30 |

*Source*: World Bank T&D specialists.

For LV distribution lines below 1 kV, costs assumed in setting tariffs in Peru for the five-year period 2013–2017 were used. The regulatory procedure assumed replacement costs of LV networks in six different settings—high-density urban, medium-density urban, low-density urban, peri-urban, concentrated rural, and low-density rural ("rural expansion"). These costs were annualized over 30 years to yield annualized capex at a real discount rate of 12 percent, yielding 2.1, 2.2, 4,7, 4,6, 3.2, and 4.9 U.S. cents per kWh billed, respectively. The regulator allows T&D losses of 10 percent, the same as the benchmark losses in this study. For simplicity, this study took costs for median-density urban and the two rural areas for urban and rural, respectively, adjusted the discount rate to 10 percent, and added an additional 25 percent to capture higher costs in SSA. These adjustments yielded 2.3 U.S. cents and 4.2 U.S. cents per kWh billed at benchmark performance for urban and rural areas, respectively. For discount rate sensitivity, these costs were adjusted upward or downward accordingly depending on the discount rate tested. The split between urban and rural delivery of electricity was approximated by taking the share of the total numbers of people connected to electricity (grid or otherwise) in urban and rural areas in 2012 in each study country according to the estimation provided in *Global Tracking Framework 2015* (World Bank 2015). These figures were scaled according to the share of low voltage sales in each country. Where sales breakdown is provide by category, LV sales are estimated by removing sales to industry, mining and export customers from total sales. Where no breakdown of sales is available, a share of 65 percent was assumed except in the Central African Republic, Comoros, and The Gambia where 100 percent of sales are assumed to be supplied at low voltage. Finally, these figures were adjusted upward or downward to account for actual T&D losses in each country.

For meters, ownership and responsibility for installation was assumed to rest with the distribution utility. A cost estimate of US$100 for new meter installation in Kenya in 2015 was used for all countries. Costs were assumed to be paid through cash flow rather than debt-financed. Annual cost of new meters was calculated by multiplying the number of new customers by US$100, where the number of new customers was taken to be the difference between the number of customers in the reference year and the year earlier. Information on the number of customers was not available for seven countries in the sample (Burundi, Central African Republic, Comoros, The Republic of Congo, Nigeria, the Seychelles, and Sudan).

## A1.5 Procedures and assumptions applied to account for sector structure

As described in section 2.3, sector structure is key for estimating opex and capex. To estimate the opex to the main utility, the starting point is the financial statement of the main utility, listed in annex 2. The procedures and assumptions applied to take account of sector structure are outlined in this section.

In the simplest case of one dominant state-owned vertically integrated utility, only one financial statement needs to be analyzed. For utilities that provide multiple services such as electricity and water, if the accounting systems do not break down costs by product line (8 out of 9 utilities), shared costs are pro-rated according to the share of electricity sales in total revenues from product sales. Relevant assumptions are detailed in annex 2 (see for example The Gambia).

In cases with more than one utility, the following procedures were applied:

- Payments for majority-private generation companies are assumed to be cost-reflective[9] and treated as 100-percent opex for the main utility. Power purchases are typically—but not always—cost-reflective, with an allowed return satisfactory to both the regulating body and the private investor. Imports and regional SPVs are also assumed to be cost-reflective. Identifying

[9] This assumption is not valid in Nigeria, but a different methodology was followed for Nigeria, as explained below.

cases where power purchases are not cost-reflective requires far more data collection and detailed examination of the data collected, and is beyond the scope of this study.

- If the seller is a state-owned generation or transmission utility, the seller's financial statements are examined to identify expenditures on loan repayments to isolate capex. The distribution company's opex is adjusted accordingly to avoid double counting capex costs, assuming that capex of the upstream company is built into the purchase price. In cases where the financial statements were not available for upstream state-owned sellers (Republic of Congo, Ghana, and Mozambique), power purchase costs were assumed to be fully cost-reflective including capex costs, and to avoid double counting calculated capex estimates exclude the assets of the companies with missing information.
- Where the main utility is selling to other utilities performing distribution activities to end-users including exports, such as those in group 4 in figure 1, the sales to these other utilities are treated as end-user sales for the main utility.
- Where there is horizontal unbundling in distribution as well as vertical unbundling, as in Ghana and Uganda, the calculated capex is scaled to the share of the total electricity generated or transmitted that is purchased by the distribution company in question. For Nigeria, this study did not follow this procedure and instead used information from the Multi-Year Tariff Order (see below for more detail).

Treating all payments to IPPs or SPVs for power purchase as opex means that opex and capex are not comparable across countries. As an (extreme) illustrative example, consider two utilities, both of which rely 100 percent on hydropower generation. The first utility is vertically integrated, so that capex is high and opex is low. The second utility is a distribution company which buys all of its electricity from SPVs running hydropower plants assumed to be operating on a commercial basis. The second utility would then have much higher opex and much smaller capex than the first.

Lastly, one of the questions this study asks is whether the power system in a given country is generating enough revenue first to pay for opex, and second how much of the capex needed can be covered. The definitions of capex and opex would be different when considered in the context of a given utility. For a utility, all purchases—whether fuels and other consumables or electricity—are opex. Being able to pay for opex is the first priority, more urgent than generating sufficient income to pay for new replacement values of assets owned by other utilities. For the power system, however, being able to cover capex is important for its financial health, and it would not be correct for this purpose to regard power purchases as consisting entirely of opex. The only power purchase that falls under opex in this context is purchase of imported electricity.

### Special case of Nigeria

Nigeria has recently unbundled the power sector and all distribution companies have 60-percent private ownership. Financial statements are not yet available. For these reasons, alternative sources of data were used:

- Actual revenues from domestic sales were provided by the World Bank's energy team working in Nigeria.
- Revenues from power exports were taken from the 2015 model for the Multi-Year Tariff Order (MYTO) and assumed to have a 100-percent collection rate.

- For capex, industry sources were used for generation asset data. The allocation of public to state owned assets may not be accurate because the privatization process was underway during 2014, the reference year for Nigeria, in which case the capex estimates may be overestimated. T&D capex estimates followed the same methodology as that used in the general methodology.
- For opex, the numbers found in the 2015 MYTO model were taken.

## A1.6 Assumptions used in the overstaffing analysis

This annex describes the approach and assumptions used to estimate overstaffing in state-owned utilities by using benchmark employment in generation, transmission, and distribution separately.

### Definitions used for overstaffing analysis

- **Actual number of staff is the number** of staff reported by state-owned utilities supplying electricity, including temporary staff, sub-contractors, and consulting staff.
- **The efficient number of staff** is estimated using reference values for generation, transmission and distribution.
- **Overstaffing ratio** is calculated as the estimated number of excess staff as a proportion of total number of actual staff.

### Data availability

- Employee and customer data are available for 36 countries. Employee data are not available for Lesotho, Nigeria, and Sudan. Ghana can be analyzed only partially because employee data are not available for staff working in state-owned generation utilities.
- A breakdown of staff between generation and T&D was available for 12 countries. These are typically the countries where there is partial or full unbundling in the sector.
- For the 8 utilities providing services other than electricity, such as water and sewerage services, the number of customers taken was the number of electricity customers. If a breakdown of employees is not provided by services, the number of staff working in electricity was pro-rated in proportion to the breakdown of revenues between electricity and other services.
- Fifteen utility companies stated owned with data publicly available on employees and customers in Latin America were studied to obtain reference values for T&D staff. Most also had data available on km of T&D infrastructure greater than 1 kV.

### Limitations of overstaffing analysis

This benchmarking analysis is necessarily simplified to be able to cover dozens of countries for cross-country comparison. Results for any individual country should not be used as a substitute for an in-depth country-level analysis. Limitations are discussed below.

- Latin America may not be a fair comparison to use for optimal employment in T&D:
  - Density of customers may be much higher in Latin America with much higher per capita income and urbanization and electrification rates compared to SSA.
  - Outsourcing of operations and maintenance is common practice for electricity utilities but the degree of outsourcing varies significantly from utility to utility and there is no “optimal” level of outsourcing. Some privatized utilities in Latin America have very high levels of

outsourcing. For this reason, publicly owned utilities—which outsource at lower levels than their private peers—were chosen as more appropriate comparators for utilities in SSA.
  - Automation of network operations (such as smart meters and prepayment meters) and works in general is much less advanced in SSA than Latin America, with many processes still manually carried out, requiring larger complements of staff.
- Data limitations
  - Plant-level data are not always available within utility annual reports, the primary source of data used for estimating capex in the main section of this paper. For the purposes of the overstaffing analysis, an industry database was used for plant-level data which may introduce inconsistencies between installed capacity data used in this paper.
  - Actual capacity factors of generation plants are unknown. The approach for efficient levels of staff in generation assumes conservatively that all plants are running at full capacity.
  - Staff numbers reported by utilities may not be consistent. Reported staff numbers are assumed to be core full-time equivalent staff. Where a breakdown of staff is not available, there could be part-time employees included or non-core utility staff such as secondees. Most utilities also report a breakdown of temporary staff and casual workers. Where these are not reported separately, they may not be included in the reported total, thereby underreporting full-time equivalent staff.
  - Customer data reported by utilities may not be accurate, particularly for utilities with poor customer management systems.

### Generation assumptions used in the overstaffing analysis

Efficient levels of staffing for generation were estimated based on the type and size of each generation plant. The assumptions applied are outlined in Table A1.6 together with additional assumptions as follows:

- **Outsourcing maintenance:** Maintenance is outsourced, except in South Africa where it is known that maintenance is not outsourced. The study reduces maintenance staff assumed in Table A1.6 by 70 percent.
- **Small plants:** There are 5 staff members for O&M of any plants smaller than 2 MW.
- **Limit on operational staff**: The number of operational staff members is limited to 30 per plant for any plant with more than four units, except coal-fired generation which has no limit.
- **Technology specific assumptions:**
  - **Gas turbines versus motors:** If no turbine data are available, assume gas plants are using motorized units unless there is a turbine listed by a known manufacturer of motors, such as Wärtsilä, MAN, Hyundai, Sulzer, Catepillar, Jenbach, and Cummins.
  - **Wind and solar**: Assume a flat rate of five O&M staff members for plants smaller than 2 MW and 20 O&M staff members for plants larger than 2MW.
  - **Nuclear**: Assume a flat rate of 600 staff members for South Africa's nuclear plant.

**Table A1.6: Base assumptions applied for operation and maintenance staff in generation**

| Generation technology | Operation staff per $\alpha$ units | $\alpha$ units | Maintenance staff per $\beta$ units | $\beta$ units | Limit on staff |
|---|---|---|---|---|---|
| Coal | 25 | 1 | 35 | 2 | No |
| Diesel | 15 | 2 | 25 | 2 | Yes |
| Gas - motor | 15 | 2 | 25 | 2 | Yes |
| Gas - turbine | 20 | 1 | 30 | 2 | Yes |
| Geothermal | 20 | 1 | 30 | 2 | Yes |
| HFO | 20 | 1 | 30 | 2 | Yes |
| Hydropower | 10 | 2 | 20 | 2 | Yes |
| Solar | 0 | 1 | 10 | 1 | Yes |

*Source*: World Bank industry specialists.

## Transmission and distribution assumptions used in the overstaffing analysis

The benchmark number of employees for T&D is set by km of T&D lines with voltage greater than 1 kV and the number of customers. The total numbers of employees reported in the utilities' annual reports are compared with the staff complement in utilities in three clusters of power utilities in Latin America with similar numbers of customers and km of T&D lines. Clusters were first identified in SSA, and then reference values were identified using utilities in Latin America with similar characteristics, as described below.

**Step 1: Identify SSA Clusters**

Thirty-six utilities in SSA were grouped into three clusters with the characteristics shown in Table A1.7.

**Table A1.7: Clusters in SSA**

| Cluster | Median customer size | Median km of T&D > 1kV |
|---|---|---|
| 1 | 100,000 | 1,800 |
| 2 | 350,000 | 9,100 |
| 3 | 1,300,000 | 39,200 |

*Source*: World Bank staff analysis of utility financial statements and annual reports

**Step 2: Identify reference values for employees in utilities in Latin America**

Fifteen state-owned utilities in Argentina, Brazil, Colombia, Paraguay, and Uruguay were used to derive reference values, each mapped to one of the three clusters (Table A1.8 and Table A1.9).

**Table A1.8: Clusters in Latin America used to identify reference values for customers per employee**

| Cluster | Median customer size | Median km of T&D >1kV | Average customers per employee |
|---|---|---|---|
| 1 | 100,000 | 2,621 | 297 |
| 2 | 330,000 | 8,601 | 440 |
| 3 | 1,300,000 | 24,123 | 571 |

*Source*: World Bank staff analysis of utility financial statements and annual reports

**Table A1.9: Utilities used for reference values**

| Company | Country | Customers | Total employees | HV+MV km | Customers/ employee |
|---|---|---|---|---|---|
| Eletrobras Distribuição Roraima | Brazil | 102,079 | 290 | — | 352 |
| Santa Maria | Brazil | 103,304 | 309 | 4,342 | 334 |
| DMED | Brazil | 71,493 | 246 | 900 | 291 |
| Sulgipe | Brazil | 136,605 | 642 | — | 213 |
| EDEMSA | Argentina | 412,242 | 694 | 8,601 | 594 |
| EMSA | Colombia | 274,284 | 580 | 8,548 | 473 |
| CHEC | Colombia | 386,264 | 896 | 9,646 | 431 |
| Electroacre | Brazil | 240,039 | 916 | — | 262 |
| CEB | Brazil | 980,969 | 1,044 | 10,849 | 940 |
| CEEE | Brazil | 1,573,248 | 2,938 | 54,742 | 535 |
| Eletrobras Distribuição Alagoas | Brazil | 1,013,971 | 1,016 | 24,123 | 998 |
| Ande | Paraguay | 1,226,630 | 3,755 | 38,853 | 327 |
| UTE | Uruguay | 1,373,559 | 6,549 | 4,445 | 210 |
| Celpe | Brazil | 3,486,000 | 8,395 | — | 415 |

*Sources*: Utility financial statements and annual reports
*Note*: DMED = Depto Municipal de Eletricidade; EDEMSA = Empresa Distribuidora de Electricidad de Mendoza Sociedad Anónima; EMSA = Electrificadora del Meta Sociedad Anónima; CHEC = Central Hidroeléctrica de Caldas; CEB = Companhia Energética de Brasília; CEEE = Comissão Estadual de Energia Elétrica; UTE = Administración Nacional de Usinas y Trasmisiones Eléctricas; — = not available

## Annex 2: Country references, meta-data, and assumptions

### Table A2: Country references, meta-data, and assumptions

| Country | Reference year | Region | Reference utility | FY-end | Utility service coverage | Financial statements publicly available | Audited statements available | Comments |
|---|---|---|---|---|---|---|---|---|
| **Benin** | 2013 | Western | SBEE (Société Béninoise d'Energie Electrique) | 31-Dec | Electricity only | No | No | Majority of grid power is purchased from CEB, a regional utility supplying Benin and Togo. |
| **Botswana** | 2013 | Southern | BPC (Botswana Power Company) | 31-Mar | Electricity only | Yes | Yes | Data on kilometers of MV T&D data not available. |
| **Burkina Faso** | 2014 | Western | Sonabel (Société Nationale d'électriité du Burkina) | 31-Dec | Electricity only | No | No | |
| **Burundi** | 2014 | Central | Regideso | 31-Dec | Electricity & water | No | No | Financial statements do not provide cost allocation of shared costs between electricity and water. Electricity assumed to account for 65% of costs shared between electricity and water, based on electricity revenue as a share of total revenue in the reference year. |
| **Cameroon** | 2014 | Central | Energy of Cameroon | 31-Dec | Electricity only | Yes | No | |
| **Cape Verde** | 2012 | Island | ELECTRA (Empresa de electricidade e água) | 31-Dec | Electricity & water | Yes | Yes | Financial statements do not provide cost allocation of shared costs between electricity and water. Electricity assumed to account for 86% of costs shared between electricity and water, based on electricity revenue as a share of total revenue in the reference year. |
| **Central African Republic** | 2014 | Central | Enerca (Energie centrafricaine) | 31-Dec | Electricity only | No | No | |
| **Comoros** | 2012 | Island | MAMWE (Madji na Mwendje ya Komori) | 31-Dec | Electricity & water | No | No | Financial statements do not provide cost allocation of shared costs between electricity and water. Electricity assumed to account for 92% of costs shared between electricity and water, based on electricity revenue as a share of total revenue in the reference year. |
| **Congo, Rep.** | 2012 | Central | SNE (Société nationale d'électricité) | 31-Dec | Electricity only | No | No | Financial statements for Centrale Electrique du Congo unavailable. |

| Country | Reference year | Region | Reference utility | FY-end | Utility service coverage | Financial statements publicly available | Audited statements available | Comments |
|---|---|---|---|---|---|---|---|---|
| **Côte d'Ivoire** | 2014 | Western | CIE (Compagnie Ivoirienne d'Électricité) | 31-Dec | Electricity only | No | No | |
| **Ethiopia** | 2012 | Eastern | Ethiopia Electric Power Company | 30-Jun | Electricity only | No | No | World-Bank-adjusted financial statements used. |
| **Gabon** | 2014 | Central | SEEG (Société d'Energie Electrique du Gabon) | 31-Dec | Electricity & water | Yes | Yes | Financial statements do not provide cost allocation of shared costs between electricity and water. Electricity assumed to account for 87% of costs shared between electricity and water, based on electricity revenue as a share of total revenue in the reference year. |
| **Gambia, The** | 2014 | Western | NAWEC (National Water and Electricity Company) | 31-Dec | Electricity, water & sewerage | No | Yes | Financial statements do not provide cost allocation of shared costs between electricity and water. Electricity assumed to account for 84% of costs shared between electricity and water, based on electricity revenue as a share of total revenue in the reference year. |
| **Ghana** | 2013 | Western | ECG (Electricity Company of Ghana) | 31-Dec | Electricity only | Yes | Yes | ECG accounted for 69% of end-user sales in reference year. Capital costs estimates from state owned generation utilities adjusted accordingly. Financial statements for Bui Power (one of the generation utilities) not available. |
| **Guinea** | 2013 | Western | Électricité de Guinée | 31-Dec | Electricity only | No | No | |
| **Kenya** | 2015 | Eastern | Kenya Power Limited Company | 30-Jun | Electricity only | Yes | Yes | |
| **Lesotho** | 2010 | Southern | Lesotho Electricity Company | 31-Mar | Electricity only | Yes | Yes | |
| **Liberia** | 2014 | Western | Liberia Electricity Company | 30-Jun | Electricity only | No | No | |
| **Madagascar** | 2014 | Island | JIRAMA (Jiro Sy Rano Malagasy) | 31-Dec | Electricity and water | Yes | Yes | Financial statements do not provide cost allocation of shared costs between electricity and water. Electricity assumed to account for 87% of costs shared between electricity and water, based on electricity revenue as a share of total revenue in the reference year. |

| Country | Reference year | Region | Reference utility | FY-end | Utility service coverage | Financial statements publicly available | Audited statements available | Comments |
|---|---|---|---|---|---|---|---|---|
| **Malawi** | 2014 | Southern | Escom (Electricity supply corporation of Malawi) | 30-Jun | Electricity only | Yes | Yes | |
| **Mali** | 2014 | Western | Energie du Mali | 31-Dec | Electricity only | Yes | Yes | |
| **Mauritania** | 2013 | Western | SOMELEC (Société Mauritanienne d'Electricité) | 31-Dec | Electricity only | No | Yes | |
| **Mauritius** | 2013 | Island | CEB (Central Electricity Board) | 31-Dec | Electricity only | Yes | Yes | |
| **Mozambique** | 2014 | Southern | EDM (Electricidade de Moçambique) | 31-Dec | Electricity only | Yes | Yes | 30% of estimated capital costs for Hydro Cahorra Bassa assigned to Mozambique reflecting the share of production sold to EDM (remainder is exported to Eskom and ZESA). |
| **Niger** | 2014 | Western | Nigelec (Société Nigerienne d'Électricité) | 31-Dec | Electricity only | Yes | No | |
| **Nigeria** | 2014 | Western | MYTO model | 31-Dec | Electricity only | No | No | Country-specific approach used for funding-gap estimate due to unavailability of audited statements. See section A1.4. |
| **Rwanda** | 2013 | Central | EWSA (Electricity, Water and Sanitation Authority) | 30-Jun | Electricity and water | No | Yes | Financial statements do not provide cost allocation of shared costs between electricity and water. Electricity assumed to account for 82% of costs shared between electricity and water, based on electricity revenue as a share of total revenue in the reference year. |
| **São Tomé and Príncipe** | 2014 | Island | EMAE (Empresa de água e electricidade) | 31-Dec | Electricity & water | No | No | Financial statements do not provide cost allocation of shared costs between electricity and water. Electricity assumed to account for 82% of costs shared between electricity and water, based on electricity revenue as a share of total revenue in the reference year. |
| **Senegal** | 2013 | Western | SENELEC (Société Nationale d'Electricité du Sénégal) | 31-Dec | Electricity only | No | Yes | |

| Country | Reference year | Region | Reference utility | FY-end | Utility service coverage | Financial statements publicly available | Audited statements available | Comments |
|---|---|---|---|---|---|---|---|---|
| **Seychelles** | 2014 | Island | PUC (Public Utilities Corporation) | 31-Dec | Electricity & water & sewerage | Yes | Yes | |
| **Sierra Leone** | 2012 | Western | NPA (National Power Authority) | 31-Dec | Electricity only | No | No | |
| **South Africa** | 2014 | Southern | Eskom | 31-Mar | Electricity only | Yes | Yes | Eskom used as the reference utility which represents more than 60% of the retail market in South Africa. Sufficient data not available for municipalities. |
| **Sudan** | 2014 | Eastern | Sudan Electricity Distribution Company | 31-Dec | Electricity only | No | No | |
| **Swaziland** | 2014 | Southern | Swaziland Electricity Company | 31-Mar | Electricity only | Yes | Yes | |
| **Tanzania** | 2014 | Eastern | TANESCO (Tanzania Electricity Supply Company) | 30-Jun | Electricity only | Yes | Yes | TANESCO changed its fiscal year so in the case of Tanzania an 18-month period is covered in the analysis reflecting the latest financial statements available covering the period Jan 2014–Jun 2015. |
| **Togo** | 2013 | Western | CEET (Compagnie Energie Electrique du Togo) | 31-Dec | Electricity only | No | No | Majority of grid power is purchased from CEB, a regional utility supplying Benin and Togo. |
| **Uganda** | 2014 | Eastern | Umeme | 31-Dec | Electricity only | Yes | Yes | Umeme accounts for 94% of end-user sales in the reference year. Balance of sales are done by UETCL (exports) and small rural concessions. |
| **Zambia** | 2014 | Southern | ZESCO | 31-Dec | Electricity only | No | Yes | ZESCO FY-end changed from Mar 31 to Dec 31 in FY14. |
| **Zimbabwe** | 2012 | Southern | Zimbabwe Transmission and Distribution Company | 31-Dec | Electricity only | No | Yes | |

*Source*: World Bank staff's review of utility data and publications.
*Note*: FY = financial year; MYTO = Multi-Year Tariff Order (not a utility); UETCL = Uganda Electricity Transmission Company Limited.

# Annex 3: Installed capacity data

### Table A3.1: Installed capacity and other parameters in MW in 2014

| Country | Hydro-power | Natural gas | Diesel and HFO | Coal | Nuclear | Other renewable energy | Total installed capacity |
|---|---|---|---|---|---|---|---|
| Angola | 1,126 | 326 | 925 | 0 | 0 | 0 | **2,377** |
| Benin | 0 | 100 | 249 | 0 | 0 | 0 | **349** |
| Botswana | 0 | 0 | 160 | 732 | 0 | 1 | **893** |
| Burkina Faso | 32 | 0 | 253 | 0 | 0 | 0 | **285** |
| Burundi | 25 | 0 | 21 | 0 | 0 | 0 | **45** |
| Cameroon | 732 | 216 | 301 | 0 | 0 | 0 | **1,249** |
| Cape Verde | 0 | 0 | 107 | 0 | 0 | 31 | **138** |
| Central African Republic | 19 | 0 | 7 | 0 | 0 | 0 | **26** |
| Chad | 0 | 0 | 125 | 0 | 0 | 0 | **125** |
| Comoros | 0 | 0 | 27 | 0 | 0 | 0 | **27** |
| Congo, Dem. Rep. | 2,488 | 28 | 0 | 0 | 0 | 0 | **2,516** |
| Congo, Rep. | 234 | 350 | 44 | 0 | 0 | 0 | **628** |
| Côte d'Ivoire | 604 | 1,028 | 0 | 0 | 0 | 0 | **1,632** |
| Equatorial Guinea | 128 | 136 | 38 | 0 | 0 | 0 | **302** |
| Eritrea | 0 | 0 | 145 | 0 | 0 | 2 | **147** |
| Ethiopia | 1,945 | 0 | 0 | 0 | 0 | 149 | **2,094** |
| Gabon | 170 | 244 | 93 | 0 | 0 | 0 | **507** |
| Gambia, The | 0 | 0 | 101 | 0 | 0 | 0 | **101** |
| Ghana | 1,580 | 1,248 | 0 | 0 | 0 | 3 | **2,831** |
| Guinea | 127 | 0 | 211 | 0 | 0 | 0 | **338** |
| Guinea-Bissau | 0 | 0 | 11 | 0 | 0 | 0 | **11** |
| Kenya | 818 | 173 | 524 | 0 | 0 | 370 | **1,885** |
| Lesotho | 72 | 0 | 0 | 0 | 0 | 0 | **72** |
| Liberia | 0 | 0 | 22 | 0 | 0 | 0 | **22** |
| Madagascar | 163 | 0 | 406 | 0 | 0 | 0 | **569** |
| Malawi | 351 | 0 | 0 | 0 | 0 | 0 | **351** |
| Mali | 321 | 29 | 270 | 0 | 0 | 0 | **620** |
| Mauritania | 0 | 0 | 155 | 0 | 0 | 15 | **170** |
| Mauritius | 58 | 226 | 312 | 215 | 0 | 0 | **811** |
| Mozambique | 2,186 | 7 | 191 | 0 | 0 | 0 | **2,383** |
| Namibia | 332 | 0 | 35 | 120 | 0 | 0 | **487** |
| Niger | 0 | 0 | 94 | 32 | 0 | 0 | **126** |
| Nigeria | 1,958 | 8,584 | 42 | 0 | 0 | 0 | **10,584** |
| Rwanda | 69 | 4 | 48 | 0 | 0 | 9 | **129** |
| São Tomé and Príncipe | 2 | 0 | 31 | 0 | 0 | 0 | **33** |
| Senegal | 0 | 84 | 569 | 0 | 0 | 0 | **653** |
| Seychelles | 0 | 0 | 98 | 0 | 0 | 6 | **104** |
| Sierra Leone | 57 | 0 | 37 | 0 | 0 | 0 | **94** |
| Somalia | 0 | 0 | 16 | 0 | 0 | 0 | **16** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| South Africa | 2,071 | 2,689 | 0 | 38,442 | 1,940 | 1,885 | **47,027** |
| South Sudan | 0 | 0 | 22 | 0 | 0 | 0 | **22** |
| Sudan | 1,599 | 0 | 1,688 | 400 | 0 | 0 | **3,686** |
| Swaziland | 60 | 25 | 10 | 0 | 0 | 0 | **95** |
| Tanzania | 565 | 574 | 450 | 0 | 0 | 20 | **1,609** |
| Togo | 68 | 0 | 263 | 0 | 0 | 0 | **331** |
| Uganda | 692 | 65 | 136 | 0 | 0 | 0 | **892** |
| Zambia | 2,228 | 0 | 140 | 0 | 0 | 0 | **2,368** |
| Zimbabwe | 750 | 0 | 0 | 1,220 | 0 | 0 | **1,970** |
| **Total** | **23,628** | **16,134** | **8,376** | **41,161** | **1,940** | **2,490** | **93,729** |
| % of total capacity | 25% | 17% | 9% | 44% | 2% | 3% | **100%** |
| **Total excluding South Africa** | **21,557** | **13,445** | **8,376** | **2,719** | **0** | **605** | **46,702** |
| % of total capacity | 46% | 29% | 18% | 6% | 0% | 1% | **100%** |

*Sources*: Utility annual reports and other documents
*Note:* Data include grid connected commissioned generation plants including isolated grids. Data do not include decommissioned plants or plants under construction. Other renewable energy includes geothermal, solar, wind, and biomass. Data include regional projects physically located within national boundaries. Dual fuel and cogeneration are recorded under natural gas.

### Table A3.2: Installed capacity and other parameters – in the reference year or latest year with available data

| | Total capacity | Available capacity | Availability factor | Peak demand | Reserve margin |
|---|---|---|---|---|---|
| | MW | MW | % | MW | % |
| Angola_2011 | 1,586 | 1,083 | 68% | 1,034.0 | 5% |
| Benin_2013 | 169 | 40 | 24% | — | — |
| Botswana_2013 | 893 | — | — | 572.1 | — |
| Burkina Faso_2014 | 285 | — | — | 218.0 | — |
| Burundi_2014 | 45 | — | — | 57.47 | — |
| Cameroon_2014 | 1,249 | — | — | 713.0 | — |
| Cape Verde_2012 | 138 | — | — | 68.3 | — |
| Central African Republic_2014 | 26 | — | — | — | — |
| Chad_2012 | 125 | — | — | — | — |
| Comoros_2012 | 27 | — | — | 22.6 | — |
| Congo, Dem. Rep._2013 | 2,444 | 1,502 | 61% | — | — |
| Congo, Rep._2012 | 600 | — | — | 265.0 | — |
| Côte d'Ivoire_2014 | 1,632 | — | — | 1,148.0 | — |
| Equatorial Guinea_2011 | 46 | — | — | — | — |
| Eritrea_2011 | 141 | — | — | — | — |
| Ethiopia_2012 | 2,167 | 1,881 | 87% | 1,237.0 | 34% |
| Gabon_2014 | 507 | 353 | 70% | 353.2 | 0% |
| Gambia, The_2014 | 101 | 57 | 57% | — | — |
| Ghana_2013 | 2,812 | 2,267 | 81% | 1,943.0 | 14% |

| | | | | | |
|---|---|---|---|---|---|
| Guinea_2013 | 338 | 169 | 50% | 162.0 | 4% |
| Guinea-Bissau_2014 | 11 | 7 | 64% | — | — |
| Kenya_2015 | 2,299 | 2,228 | 97% | 1,512.0 | 32% |
| Lesotho_2010 | 72 | — | — | 138.0 | — |
| Liberia_2014 | 22 | 14 | 65% | 10.9 | 24% |
| Madagascar_2014 | 569 | 450 | 79% | — | — |
| Malawi_2014 | 351 | 341 | 97% | 323.9 | 5% |
| Mali_2014 | 352 | — | — | 245.0 | — |
| Mauritania_2013 | 170 | 107 | 63% | 110.0 | -3% |
| Mauritius_2013 | 776 | 684 | 88% | 441.1 | 36% |
| Mozambique_2014 | 2,520 | — | — | 831.0 | — |
| Namibia_2013 | 487 | 392 | 80% | 614.0 | -57% |
| Niger_2014 | 126 | — | — | 146.1 | — |
| Nigeria_2014 | 10,584 | 6,493 | 61% | — | — |
| Rwanda_2013 | 93 | — | — | 92.0 | — |
| São Tomé and Príncipe_2014 | 33 | — | — | — | — |
| Senegal_2013 | 757 | 684 | 90% | 483.0 | 29% |
| Seychelles_2014 | 104 | — | — | 59.0 | — |
| Sierra Leone_2012 | 94 | — | — | — | — |
| Somalia_2011 | 16 | — | — | — | — |
| South Africa_2014 | 47,027 | 44,895 | 95% | 36,170.0 | 19% |
| South Sudan_2013 | 22 | — | — | 22.0 | — |
| Sudan_2014 | 3,686 | — | — | — | — |
| Swaziland_2014 | 95 | — | — | 226.3 | — |
| Tanzania_2015 | 1,626 | — | — | 934.6 | — |
| Togo_2013 | 264 | — | — | 162.6 | — |
| Uganda_2014 | 892 | — | — | 580.0 | — |
| Zambia_2014 | 2,366 | 2,211 | 93% | — | — |
| Zimbabwe_2012 | 1,970 | 1,257 | 64% | 1,546.0 | -23% |
| | | | | | |
| **Total for countries with available capacity data (20 countries)** | 77,501 | 67,110 | 87% | | |
| **Total for countries with available capacity data (excluding South Africa)** | 30,474 | 22,215 | 73% | | |
| | | | | | |
| **Total for countries with available capacity data and peak demand data (14 countries)** | | 56,357 | | 45,940 | 18% |
| **Total for countries with available capacity data and peak demand data (excluding South Africa)** | | 11,462 | | 9,770 | 15% |

Source: utility annual reports and other documents
*Note*: The year following each country name is the reference year for countries included in the QFD analysis, or the latest year with available data for capacity, peak demand, or both for countries not included in the QFD analysis. For the purposes of the availability factor, reported available capacity is assumed to correspond to domestic capacity excluding regional projects. Reserve margins calculations are based on available capacity relative to peak demand. — = not available

## Annex 4: Data on existing assets used for capex estimates

**Table A4.1: State-owned installed capacity (MW) in the reference year**

| Country | Hydropower | Natural gas | Diesel and HFO | Coal | Nuclear | Other renewable energy | Total Installed capacity |
|---|---|---|---|---|---|---|---|
| Benin | 0 | 0 | 169 | 0 | 0 | 0 | 169 |
| Botswana | 0 | 0 | 0 | 732 | 0 | 1 | 733 |
| Burkina Faso | 32 | 0 | 253 | 0 | 0 | 0 | 285 |
| Burundi | 27 | 0 | 8 | 0 | 0 | 0 | 35 |
| Cameroon | 732 | 0 | 215 | 0 | 0 | 0 | 947 |
| Cape Verde | 0 | 0 | 107 | 0 | 0 | 8 | 115 |
| Central African Republic | 19 | 0 | 7 | 0 | 0 | 0 | 26 |
| Comoros | 0 | 0 | 27 | 0 | 0 | 0 | 27 |
| Congo, Rep. | 209 | 350 | 41 | 0 | 0 | 0 | 600 |
| Côte d'Ivoire | 604 | 100 | 0 | 0 | 0 | 0 | 704 |
| Ethiopia | 1,946 | 0 | 133 | 0 | 0 | 88 | 2,167 |
| Gabon | 170 | 174 | 93 | 0 | 0 | 0 | 437 |
| Gambia, The | 0 | 0 | 101 | 0 | 0 | 0 | 101 |
| Ghana | 1,580 | 898 | 0 | 0 | 0 | 3 | 2,480 |
| Guinea | 127 | 0 | 161 | 0 | 0 | 0 | 288 |
| Kenya | 820 | 60 | 221 | 0 | 0 | 515 | 1,615 |
| Lesotho | 72 | 0 | 0 | 0 | 0 | 0 | 72 |
| Liberia | 0 | 0 | 22 | 0 | 0 | 0 | 22 |
| Madagascar | 146 | 0 | 181 | 0 | 0 | 0 | 327 |
| Malawi | 351 | 0 | 0 | 0 | 0 | 0 | 351 |
| Mali | 53 | 29 | 156 | 0 | 0 | 0 | 238 |
| Mauritania | 0 | 0 | 170 | 0 | 0 | 0 | 170 |
| Mauritius | 61 | 78 | 361 | 0 | 0 | 1 | 501 |
| Mozambique | 2,184 | 7 | 91 | 0 | 0 | 0 | 2,281 |
| Niger | 0 | 0 | 64 | 0 | 0 | 0 | 64 |
| Nigeria | 1,958 | 5,911 | 29 | 0 | 0 | 0 | 7,899 |
| Rwanda | 40 | 0 | 28 | 0 | 0 | 0 | 69 |
| São Tomé and Príncipe | 2 | 0 | 23 | 0 | 0 | 0 | 25 |
| Senegal | 0 | 59 | 493 | 0 | 0 | 0 | 552 |
| Seychelles | 0 | 0 | 98 | 0 | 0 | 6 | 104 |
| Sierra Leone | 57 | 0 | 37 | 0 | 0 | 0 | 94 |
| South Africa | 2,061 | 2,426 | 0 | 37,754 | 1,940 | 100 | 44,281 |
| Sudan | 1,599 | 0 | 1,428 | 400 | 0 | 0 | 3,426 |
| Swaziland | 60 | 0 | 10 | 0 | 0 | 0 | 70 |
| Tanzania | 562 | 305 | 125 | 0 | 0 | 0 | 991 |
| Togo | 2 | 0 | 121 | 0 | 0 | 0 | 123 |
| Uganda | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Zambia | 2,172 | 0 | 10 | 0 | 0 | 0 | 2,182 |
| Zimbabwe | 750 | 0 | 0 | 1,220 | 0 | 0 | 1,970 |

*Source*: Utility annual reports and other documents.

*Note*: Data correspond to state-owned installed capacity on commissioned generation plants, excluding regional projects. Dual fuel and cogeneration are recorded under natural gas. Other renewable energy includes geothermal, solar, wind, and biomass.

### Table A4.2: State-owned transmission and distribution line data (km) in the reference year or latest year with available data

| Country | HV (110 kV and above) | MV to HV (66 kV–109 kV) | MV (1–66 kV) | Total above 1kV |
|---|---|---|---|---|
| Angola_2011 | 2,094 | 0 | 738 | **2,832** |
| Benin_2013 | 136 | 0 | 3,408 | **3,544** |
| Botswana_2013 | 3,023 | 0 | — | **3,023** |
| Burkina Faso_2014 | 3,452 | 0 | 471 | **3,923** |
| Burundi_2014 | 0 | 322 | 1,779 | **2,101** |
| Cameroon_2014 | 0 | 2,232 | 16,785 | **19,017** |
| Cape Verde_2012 | 0 | 0 | 859 | **859** |
| Central African Republic_2014 | 0 | 0 | 225 | **225** |
| Chad_2012 | 0 | 0 | 0 | **0** |
| Comoros_2012 | 0 | 0 | 588 | **588** |
| Congo, Dem. Rep._2013 | 30 | 0 | 4,483 | **4,513** |
| Congo, Rep._2012 | 1,479 | 0 | 1,070 | **2,549** |
| Côte d'Ivoire_2014 | 4,700 | 0 | 21,700 | **26,400** |
| Equatorial Guinea_2011 | 0 | 0 | 0 | **0** |
| Eritrea_2011 | 0 | 0 | 0 | **0** |
| Ethiopia_2012 | 9,568 | 1,973 | 87,518 | **99,059** |
| Gabon_2014 | 715 | 0 | 4,746 | **5,461** |
| Gambia, The_2014 | 0 | 0 | 528 | **528** |
| Ghana_2013 | 5,100 | 0 | 37,469 | **42,569** |
| Guinea_2013 | 325 | 0 | 1,053 | **1,378** |
| Guinea-Bissau_2014 | 0 | 0 | 458 | **458** |
| Kenya_2015 | 4,054 | 1,212 | 54,193 | **59,459** |
| Lesotho_2010 | 1,050 | 0 | 0 | **1,050** |
| Liberia_2014 | 0 | 27 | 60 | **87** |
| Madagascar_2014 | 0 | 0 | 3,217 | **3,217** |
| Malawi_2014 | 1,274 | 1,121 | 12,250 | **14,645** |
| Mali_2014 | 766 | 222 | 2,055 | **3,043** |
| Mauritania_2013 | 0 | 0 | 0 | **0** |
| Mauritius_2013 | 0 | 309 | 3,427 | **3,736** |
| Mozambique_2014 | 4,781 | 579 | 15,269 | **20,629** |
| Namibia_2013 | 7,513 | 3,605 | 21,877 | **32,995** |
| Niger_2014 | 0 | 0 | 4,472 | **4,472** |
| Nigeria_2014 | 12,325 | 0 | 125,000 | **137,325** |
| Rwanda_2013 | 253 | 96 | 3,030 | **3,379** |
| São Tomé and Príncipe_2014 | 0 | 0 | 149 | **149** |
| Senegal_2013 | 501 | 0 | 7,822 | **8,323** |
| Seychelles_2014 | 0 | 0 | 330 | **330** |
| Sierra Leone_2012 | 205 | 0 | 0 | **205** |
| Somalia_2011 | 0 | 0 | 0 | **0** |
| South Africa_2014 | 31,107 | 0 | 48,704 | **79,811** |
| South Sudan_2013 | 0 | 0 | 0 | **0** |

| Country | HV (110 kV and above) | MV to HV (66 kV–109 kV) | MV (1–66 kV) | Total above 1kV |
|---|---|---|---|---|
| Sudan_2014 | 3,427 | 0 | 63,719 | **67,146** |
| Swaziland_2014 | 296 | 970 | 10,034 | **11,300** |
| Tanzania_2015 | 4,288 | 579 | 22,396 | **27,263** |
| Togo_2013 | 0 | 75 | 2,647 | **2,722** |
| Uganda_2014 | 1,592 | 35 | 11,572 | **13,199** |
| Zambia_2014 | 3,014 | 1,771 | 3,137 | **7,922** |
| Zimbabwe_2012 | 5,532 | 1,742 | 65,965 | **73,239** |
| **Total** | **112,600** | **16,870** | **665,203** | **794,674** |
| **Total excluding South Africa** | **81,493** | **16,870** | **616,499** | **714,863** |

*Sources*: Utility annual reports and other documents.

*Note*: The year following each country name is the reference year for countries included in the QFD analysis, or the latest year with available data for T&D assets for countries not included in the QFD analysis.

# Annex 5: Power purchase data

**Table A5: Power purchase data - reference year or latest year available**

| | Power purchases (GWh) | | | | Power purchases (as % dispatched onto national grid) | | | |
|---|---|---|---|---|---|---|---|---|
| | Private purchases (excluding EPP) | Emergency power purchases | Import purchases | Total power purchases | Private purchases (excluding EPP) | Emergency power purchases | Import purchases | Total power purchases |
| | *GWh* | *GWh* | *GWh* | *GWh* | *%* | *%* | *%* | *%* |
| Angola_2011 | 3,287.3 | 1,109.6 | 36.0 | **4,432.9** | 58 | 20 | 1 | 78 |
| Benin_2013 | 0.0 | 0.0 | 1,097.0 | **1,097.0** | 0 | 0 | 100 | 100 |
| Botswana_2013 | 36.1 | 54.1 | 1,695.3 | **1,785.5** | 1 | 1 | 46 | 48 |
| Burkina Faso_2014 | 0.0 | 0.0 | 488.4 | **488.4** | 0 | 0 | 36 | 36 |
| Burundi_2014 | 0.0 | 24.6 | 89.4 | **113.9** | 0 | 10 | 35 | 44 |
| Cameroon_2014 | — | 0.0 | 0.0 | **0.0** | n/a | 0 | 0 | 0 |
| Cape Verde_2012 | 58.7 | 0.0 | 0.0 | **58.7** | 20 | 0 | 0 | 20 |
| Central African Republic_2014 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Chad_2012 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Comoros_2012 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Congo, Dem. Rep._2013 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Congo, Rep._2012 | 0.0 | 0.0 | 25.0 | **25.0** | 0 | 0 | 1 | 1 |
| Côte d'Ivoire_2014 | 1,385.8 | 4,565.1 | 0.0 | **5,951.0** | 17 | 56 | 0 | 73 |
| Equatorial Guinea_2011 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Eritrea_2011 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Ethiopia_2012 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Gabon_2014 | 388.0 | 0.0 | 0.0 | **388.0** | 18 | 0 | 0 | 18 |
| Gambia, The_2014 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Ghana_2013 | 1,148.0 | 0.0 | 27.0 | **1,175.0** | 9 | 0 | 0 | 9 |
| Guinea_2013 | 1.1 | 26.4 | 0.0 | **27.5** | 0 | 4 | 0 | 4 |
| Guinea-Bissau_2014 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Kenya_2015 | 2,159.1 | 62.7 | 79.4 | **2,301.2** | 23 | 1 | 1 | 25 |
| Lesotho_2010 | 0.0 | 0.0 | 220.7 | **220.7** | 0 | 0 | 33 | 33 |
| Liberia_2014 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Madagascar_2014 | 438.0 | 0.0 | 0.0 | **438.0** | 29 | 0 | 0 | 29 |
| Malawi_2014 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Mali_2014 | 95.6 | 160.0 | 850.6 | **1,106.2** | 6 | 10 | 54 | 70 |
| Mauritania_2013 | 0.0 | 0.0 | 195.2 | **195.2** | 0 | 0 | 30 | 30 |

| | Power purchases (GWh) | | | | Power purchases (as % dispatched onto national grid) | | | |
|---|---|---|---|---|---|---|---|---|
| | **Private purchases (excluding EPP)** | **Emergency power purchases** | **Import purchases** | **Total power purchases** | **Private purchases (excluding EPP)** | **Emergency power purchases** | **Import purchases** | **Total power purchases** |
| | *GWh* | *GWh* | *GWh* | *GWh* | *%* | *%* | *%* | *%* |
| Mauritius_2013 | 1,436.3 | 0.0 | 0.0 | **1,436.3** | 55 | 0 | 0 | 55 |
| Mozambique_2014 | 8.7 | 93.5 | 190.2 | **292.4** | 0 | 2 | 4 | 6 |
| Namibia_2013 | 0.0 | 0.0 | 2,888.0 | **2,888.0** | 0 | 0 | 68 | 68 |
| Niger_2014 | 47.6 | 109.2 | 727.0 | **883.7** | 5 | 12 | 78 | 94 |
| Nigeria_2014 | — | 0.0 | 0.0 | **0.0** | n/a | 0 | 0 | 0 |
| Rwanda_2013 | 10.2 | 125.2 | 88.0 | **223.4** | 2 | 24 | 17 | 43 |
| São Tomé and Príncipe_2014 | 8.7 | 0.0 | 0.0 | **8.7** | 10 | 0 | 0 | 10 |
| Senegal_2013 | 379.0 | 442.0 | 308.5 | **1,129.5** | 12 | 15 | 10 | 37 |
| Seychelles_2014 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Sierra Leone_2012 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Somalia_2011 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| South Africa_2014 | 6,022.0 | 0.0 | 10,731.0 | **16,753.0** | 3 | 0 | 5 | 7 |
| South Sudan_2013 | 0.0 | 0.0 | 0.0 | **0.0** | 0 | 0 | 0 | 0 |
| Sudan_2014 | 0.0 | 0.0 | 467.9 | **467.9** | 0 | 0 | 4 | 4 |
| Swaziland_2014 | 47.8 | 0.0 | 930.2 | **978.0** | 4 | 0 | 77 | 81 |
| Tanzania_2015 | 2,915.2 | 344.8 | 92.4 | **3,352.4** | 31 | 4 | 1 | 36 |
| Togo_2013 | 0.0 | 5.5 | 833.5 | **839.0** | 0 | 1 | 76 | 77 |
| Uganda_2014 | 3,222.7 | 0.0 | 32.7 | **3,255.4** | 99 | 0 | 1 | 100 |
| Zambia_2014 | 0.0 | 0.0 | 50.7 | **50.7** | 0 | 0 | 0 | 0 |
| Zimbabwe_2012 | 0.0 | 0.0 | 1,113.6 | **1,113.6** | 0 | 0 | 11 | 11 |

*Sources*: Utility annual reports and other documents.

*Notes*: Data are for power purchases from IPPs, EPPs, and imports. Purchases from state-owned generation companies are not included. Imports include purchases from regional SPV generation utilities, even if the generation facility is located within the borders of a given country. The year following each country name is the reference year for countries included in the QFD analysis, or the latest year with available power purchase data for countries not included in the QFD analysis.

## Annex 6: Dispatch, sales, and T&D loss data

**Table A6: Dispatch, sales, and T&D loss data for the reference utility in the reference year**

| Country | Total dispatched or purchased (GWh) | Sales (GWh) | Sales (kWh per person) | T&D losses (GWh) | T&D losses (% of GWh dispatched or purchased) |
|---|---|---|---|---|---|
| Angola_2011 | — | 2.394,14 | n/a | — | — |
| Benin_2013 | 1,102 | 875 | 85 | 227 | 21% |
| Botswana_2013 | 3,706 | 3,449 | 1,706 | 257 | 7% |
| Burkina Faso_2014 | 1,359 | 1,125 | 65 | 234 | 17% |
| Burundi_2014 | 258 | 209 | 20 | 49 | 19% |
| Cameroon_2014 | 6,080 | 4,360 | 191 | 1,720 | 28% |
| Cape Verde_2012 | 300 | 205 | 415 | 95 | 32% |
| Central African Republic_2014 | 137 | 71 | 15 | 66 | 48% |
| Chad_2012 | — | n/a | n/a | — | — |
| Comoros_2012 | 82 | 49 | 69 | 33 | 40% |
| Congo, Dem. Rep._2013 | 8,349 | 7,479 | 111 | 870 | 10% |
| Congo, Rep._2012 | 1,725 | 940 | 217 | 786 | 46% |
| Côte d'Ivoire_2014 | 8,152 | 6,466 | 311 | 1,686 | 21% |
| Equatorial Guinea_2011 | — | n/a | n/a | — | — |
| Eritrea_2011 | 337 | 273 | 46 | 64 | 19% |
| Ethiopia_2012 | 6,290 | 4,702 | 51 | 1,588 | 25% |
| Gabon_2014 | 2,172 | 1,650 | 964 | 522 | 24% |
| Gambia, The_2014 | 266 | 194 | 101 | 73 | 27% |
| Ghana_2013 | 8,479 | 6,496 | n/a | 1,983 | 23% |
| Guinea_2013 | 654 | 498 | 42 | 156 | 24% |
| Guinea-Bissau_2014 | — | 12 | 7 | — | — |
| Kenya_2015 | 9,280 | 7,655 | 168 | 1,625 | 18% |
| Lesotho_2010 | 676 | 615 | 306 | 61 | 9% |
| Liberia_2014 | 56 | 42 | 10 | 14 | 25% |
| Madagascar_2014 | 1,488 | 1,000 | 42 | 487 | 33% |
| Malawi_2014 | 1,906 | 1,456 | 87 | 450 | 24% |
| Mali_2014 | 1,578 | 1,214 | 77 | 364 | 23% |
| Mauritania_2013 | 642 | 495 | 127 | 147 | 23% |
| Mauritius_2013 | 2,613 | 2,384 | 1,894 | 229 | 9% |
| Mozambique_2014 | 4,961 | 3,855 | 146 | 1,106 | 22% |
| Namibia_2013 | 4,219 | 3,861 | 1,676 | 358 | 8% |
| Niger_2014 | 936 | 758 | 41 | 178 | 19% |

| Country | Total dispatched or purchased (GWh) | Sales (GWh) | Sales (kWh per person) | T&D losses (GWh) | T&D losses (% of GWh dispatched or purchased) |
|---|---|---|---|---|---|
| Nigeria_2014 | 30,715 | 18,819 | 105 | 11,896 | 39% |
| Rwanda_2013 | 517 | 382 | 32 | 135 | 26% |
| São Tomé and Príncipe_2014 | 90 | 51 | 258 | 38 | 43% |
| Senegal_2013 | 3,038 | 2,507 | 177 | 531 | 17% |
| Seychelles_2014 | 357 | 313 | 3,415 | 45 | 12% |
| Sierra Leone_2012 | 195 | 120 | 20 | 75 | 39% |
| Somalia_2011 | 310 | 288 | 29 | 22 | 7% |
| South Africa_2014 | 238,201 | 216,274 | 4,005 | 21,927 | 9% |
| South Sudan_2013 | 99 | 70 | 6 | 29 | 29% |
| Sudan_2014 | 11,359 | 9,709 | 250 | 1,649 | 15% |
| Swaziland_2014 | 1,209 | 1,074 | 848 | 135 | 11% |
| Tanzania_2015 | 9,434 | 7,754 | 147 | 1,680 | 18% |
| Togo_2013 | 1,091 | 784 | 115 | 307 | 28% |
| Uganda_2014 | 2,894 | 2,277 | 59 | 617 | 21% |
| Zambia_2014 | 13,812 | 12,104 | 806 | 1,708 | 12% |
| Zimbabwe_2012 | 10,079 | 8,534 | 622 | 1,545 | 15% |

*Sources*: Utility annual reports and other documents
*Notes*: The year following each country name is the reference year for countries included in the QFD analysis, or the latest year with available data for countries not included in the QFD analysis. — = not available.

## Annex 7: Quality of service data

**Table A7: Quality of service data**

| | **Data related to duration** | **Data related to frequency** |
|---|---|---|
| Burkina Faso | Average outage time of 82 hours | 2405 incidents related to load-shedding, works and incidents. |
| Cameroon | SAIDI: 105 hours | SAIFI: 25 |
| Cape Verde | Average outage time of one hour | 418 blackouts in 2012 |
| Côte d'Ivoire | Average outage time of 40 hours | |
| Gabon | Average outage time of 126 hours | |
| Gambia | Total load-shedding time of 6031 hours | 124 MV outages, 3985 LV outages |
| Ghana | 150 hours of outages per year for urban customers, 174 hours of outages for rural customers | 83 outages per year for urban customers, 92 per year for rural customers |
| Guinea | Average outage time of 21 hours | 1962 outages due to breakdowns per year |
| Liberia | SAIDI: 35 hours | SAIFI: 212 |
| Mali | Average 1 hour duration for HV outages, average 1.5 hours duration for MV outages | 70 HV outages, 224 MV outages |
| Mauritania | Average 1.2 hours duration for MV outages | 116 outages at MV level |
| Mozambique | SAIDI Transmission system: 59 hours<br>SAIDI Distribution system: 1.25 hours | SAIFI Transmission system: 52<br>SAIFI Distribution system: 1.25 |
| Senegal | 29,891 system interruptions per year | |
| Sierra Leone | Average duration of 10 hours per interruption at the MV level | Average interruption frequency of 183 per year at the MV level |
| South Africa | SAIDI: 36 | SAIFI: 20 |
| Zimbabwe | Average duration of 3 hours per outage in the transmission system | 185 interruptions in the transmission system per year |

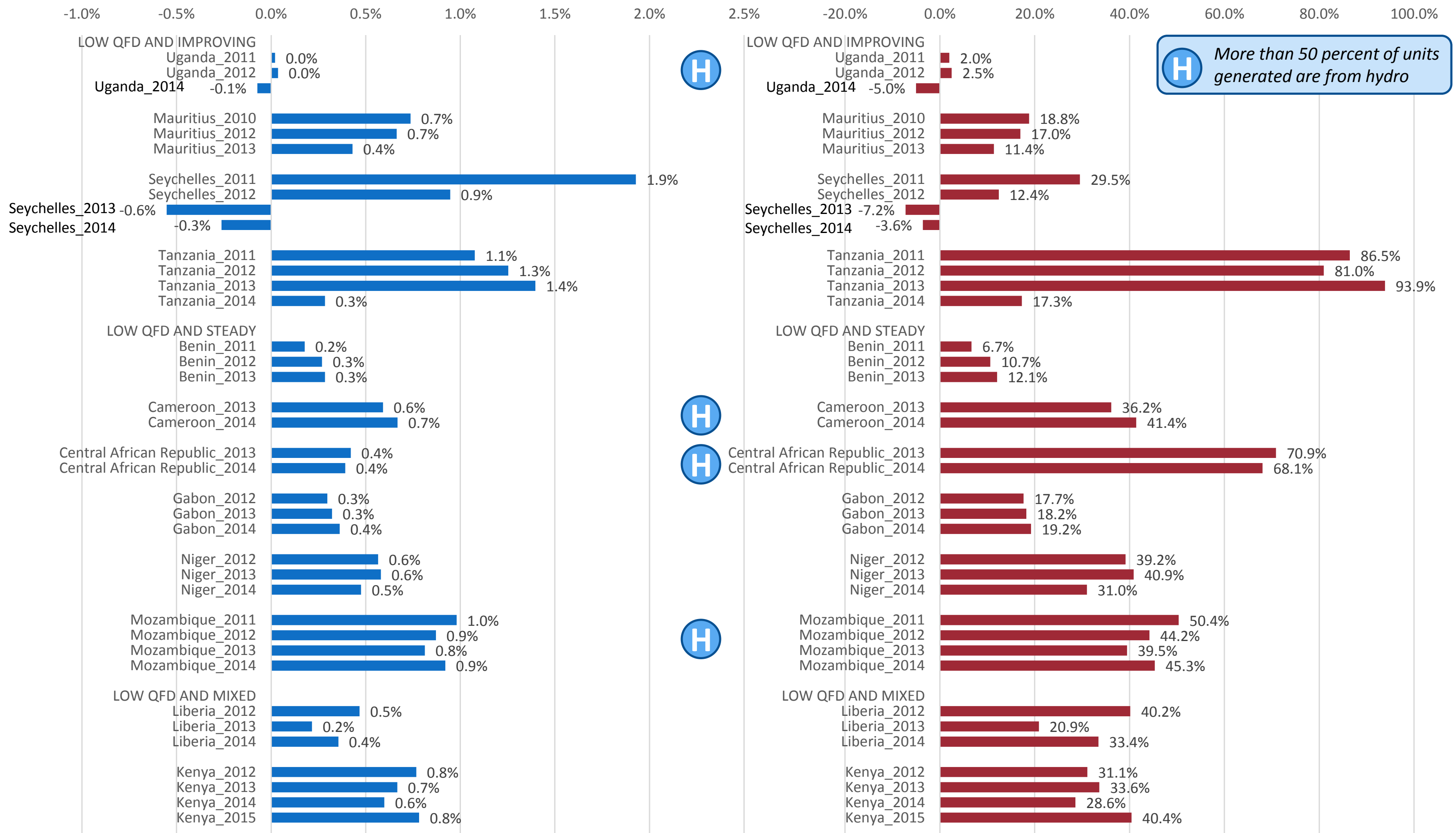
*Sources*: Utility annual reports and other documents.

# Annex 8: Multiyear results

**Table A8.1: Multiyear analysis for countries with a low QFD (less than 1 percent of GDP in the reference year)**

QFD as percent of GDP

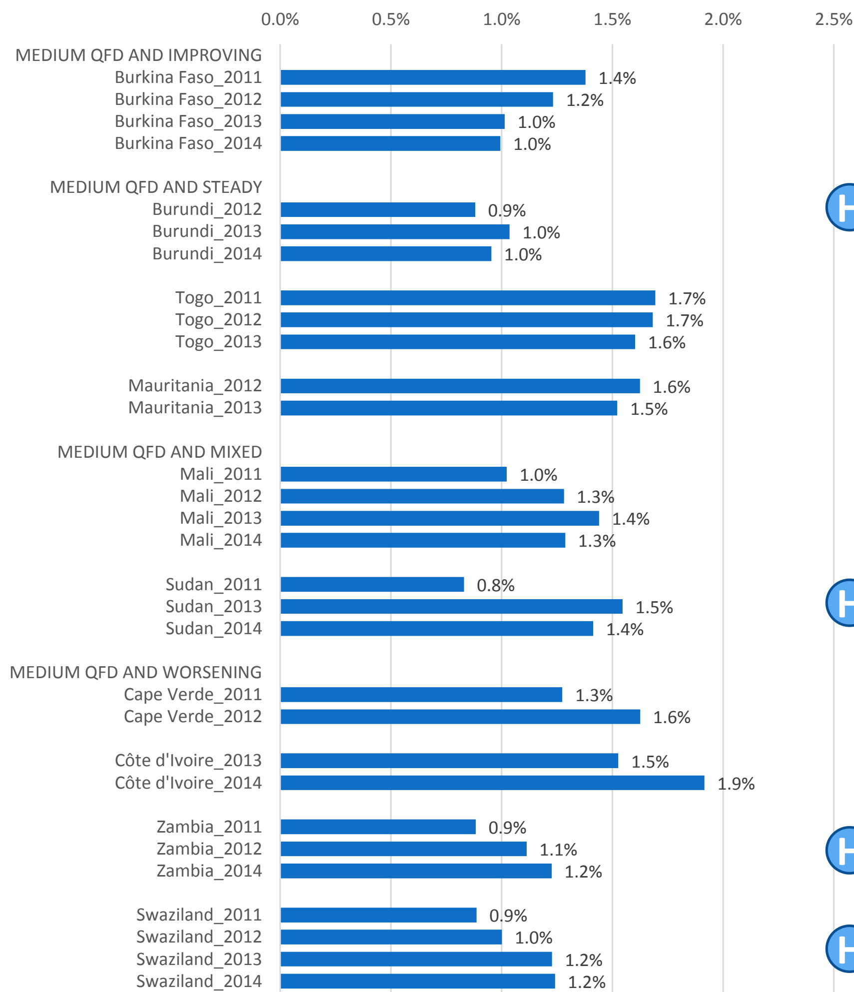
QFD as percent of revenues



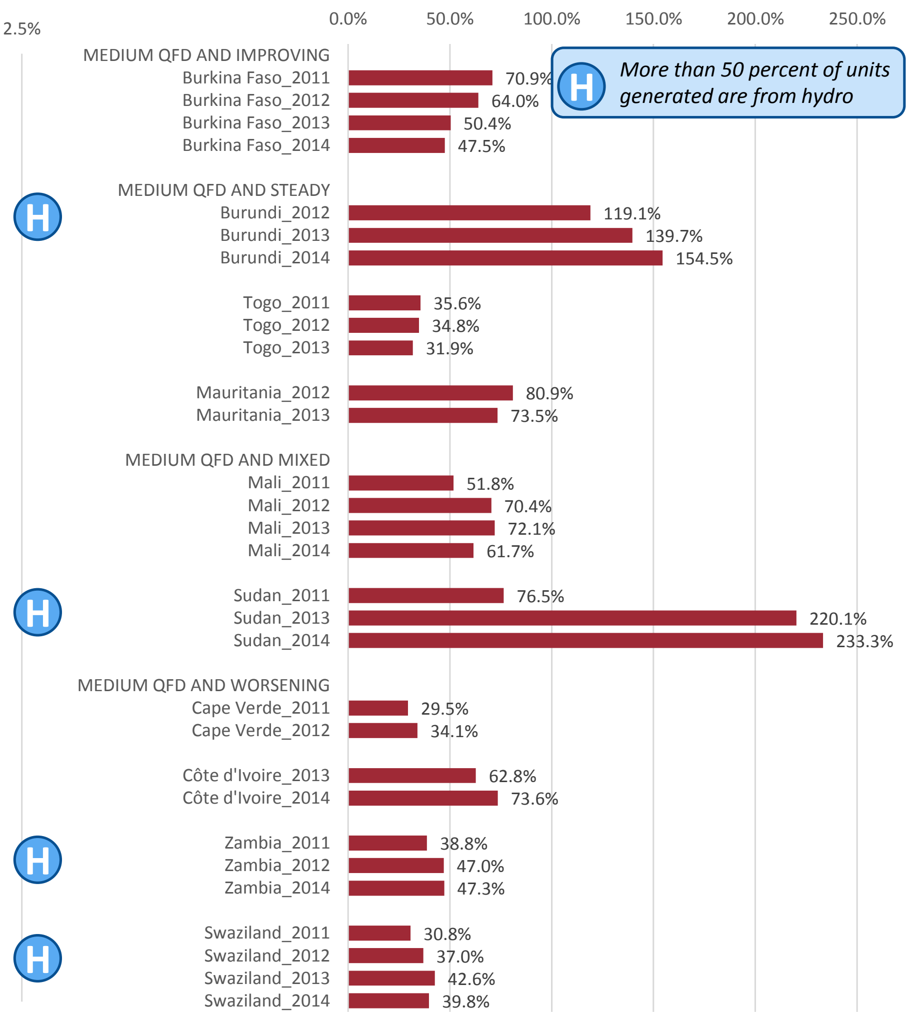

*Source*: World Bank staff calculations using utility data.

**Table A8.2: Multiyear analysis for countries with a medium QFD (1-2 percent of GDP in the reference year)**

QFD as percent of GDP



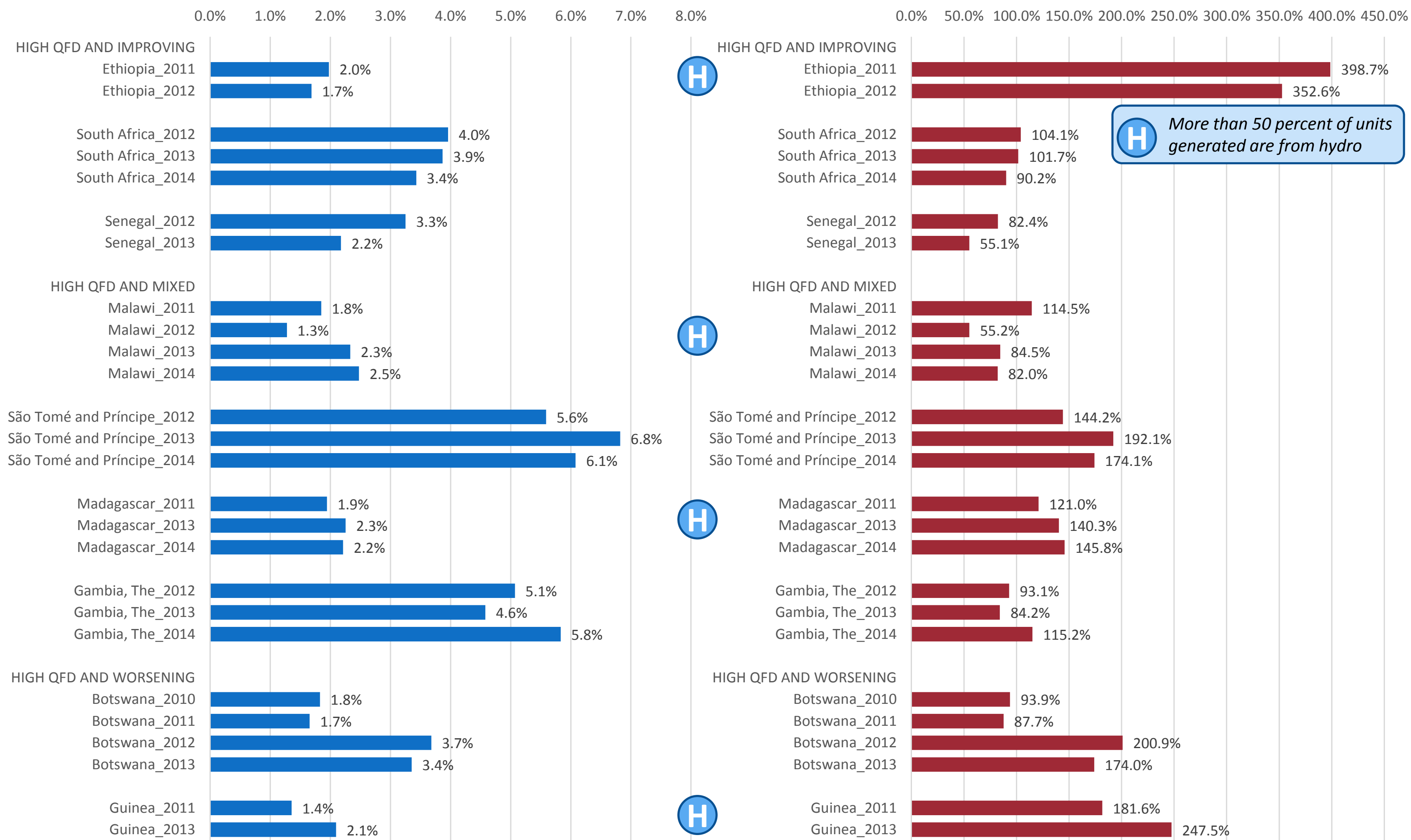

QFD as percent of revenues




*Source*: World Bank staff calculations using utility data.

**Table A8.3: Multiyear analysis for countries with a high QFD (greater than 2 percent of GDP in the reference year)**

QFD as percent of GDP QFD as percent of revenues




*Source*: World Bank staff calculations using utility data.

**Table A8.4: Comparison of AICD results and results from the present study**

| Country | Date range | | T&D losses, % | | Bill collection rate, % | | QFD as % of revenue | | Comment |
|---|---|---|---|---|---|---|---|---|---|
| | AICD | Present study | AICD | Present study | AICD | Present study | AICD | Present study | |
| Benin | 2009 | 2011–13 | 21 | 21 | 96 | 95 | 12 | 7 → 12 | Total losses and the QFD remained relatively stable. |
| Botswana | n/a | 2010–13 | 10 | 11 → 7 | 100 | 99 | 15 | 94 → 174 | Total losses remained relatively stable. Steep increase in QFD since AICD, and within the period covered by the present study, driven in part by issues with Morupule coal plant. |
| Burkina Faso | 2007–08 | 2011–14 | 18, 16 | 16 → 17 | 91 | 83 → 98 | 46, 37 | 71 → 48 | T&D losses stable, bill collections improved. QFD increased and returned to 2008 levels. |
| Cape Verde | 2000–09 | 2011–12 | 17 → 26 | 30 → 32 | 91–92 | 93 → 88 | 129 → 45 | 29 → 34 | Total losses increased, yet improvements in 2001–09 seem to have continued, driven by substantial tariff increases. |
| Central African Republic | 2004–09 | 2013–14 | 48 | 52 → 48 | 69 | 78 | 48 → 117 | 71 → 68 | T&D losses remained high, and bill collection rates low, yet QFD seems to have dropped back to 2004 levels. |
| Congo, Rep. | n/a | 2012 | 47 | 46 | 91 | 80 | 86 | 76 | T&D losses remained high, bill collection rates seem to have regressed. QFD change within a 10% margin of error. |
| Côte d'Ivoire | 2005–09 | 2013–14 | 18, 23 → 17 | 22 → 21 | 88 | 80 → 82 | 63 → 137 | 63 → 74 | Despite increasing T&D losses and reduced bill collection rates, QFD seems to have fallen. |
| Ethiopia | 2005–09 | 2011–12 | 22 | 23 → 25 | 96.5 | 87 | 133 | 399 → 353 | Substantial increase in QFD driven by major capital expansion program. |
| Ghana | Mid to late 2000s | 2013 | 25.4→ 25.6 | 23 | 89.6→ 89.3 | 95 | 37→118 | 22 | QFD reduced partly driven by bill collection rate improvement. |
| Kenya | 2001–08 | 2012–15 | 18 | 17 → 18 | 98.7 | 99 | 55 → 0 | 31 → 40 | Losses stayed consistent. QFD seems to have returned to the levels in the early 2000s after departure from cost recovery. |
| Liberia | n/a | 2012–14 | 25 | 23, 29, 25 | 93 | 82 → 94 | 158 | 40 → 21 → 33 | Losses relatively steady while QFD decreased substantially due to increase in tariffs. |
| Malawi | n/a | 2011-14 | 23 | 21→24 | 59.8 | 92→93 | 264 | 115→82 | QFD reduced in part driven by a significant increase in bill collection rate. |
| Mali | 1999–2008 | 2011–14 | 25 → 22 | 29 → 23 | 92 → 96 | 101 → 99 | 95 → 131 | 52 → 72 → 62 | Total losses steady. QFD improved from AICD period. |
| Mozambique | 2005–09 | 2011–13 | 25–27 | 20–22 | 98–100 | 97 → 98 | 41, 44, 57, 37, 44 | 50 → 45 | T&D losses improved. Bill collection remained high. QFD increased but has come back down to 2005 levels. |
| Nigeria | 2005, 2007–09 | 2014 | 30 → 20 | 39 | 63.5 → 88 | 66 | 548, 292, 220, 247 | 174 | Losses remained high. QFD, while high, fell substantially, driven in part by the privatization process. |

| Country | Date range | | T&D losses, % | | Bill collection rate, % | | QFD as % of revenue | | Comment |
|---|---|---|---|---|---|---|---|---|---|
| | **AICD** | **Present study** | **AICD** | **Present study** | **AICD** | **Present study** | **AICD** | **Present study** | |
| Senegal | 2003–07 | 2012–13 | 22 | 21 | 98.8 | 87 → 93 | 90 → 52 | 82 → 55 | T&D losses steady although bill collection worsened. QFD increased as tariffs did not keep pace with cost increases. |
| Tanzania | 2006-10 | 2011-14 | 26→15.4 | 25→18 | 94.0 | 95→92 | 175 → 87 | 86 → 17 | Bill collection rate steady. T&D losses fluctuating 15 to 26 percent. Improvement in QFD reductions continues, driven by tariff increases. |
| Zambia | n/a | 2011–14 | 12 | 17 → 13 | 96.5 | 96 | 93 | 39 → 47 | T&D losses increased and came back down. Bill collection steady. QFD marginally reduced. |

*Source*: AICD country reports and World Bank staff calculations.
*Note:* If one number is provided, it indicates only one data point was available within the stated date range. In addition to the changes in methodology, which make it difficult to compare results directly with AICD, it is unclear that T&D losses are comparable. In some cases, T&D data in AICD are referred to as “distribution losses,” which are assumed here to include transmission in addition to distribution losses.

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