CLIMATESCOPE

Sub-Saharan Africa Market Outlook 2020

Reducing risk, opening up opportunities across the world's fastest growing region

UKaid
from the British people

BloombergNEF

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62%

Increase in projected yearly PV capacity additions in 2021 against 2018

18

Sub-Saharan African countries receiving more than $10 million in renewables investment in 2018

0.4GW

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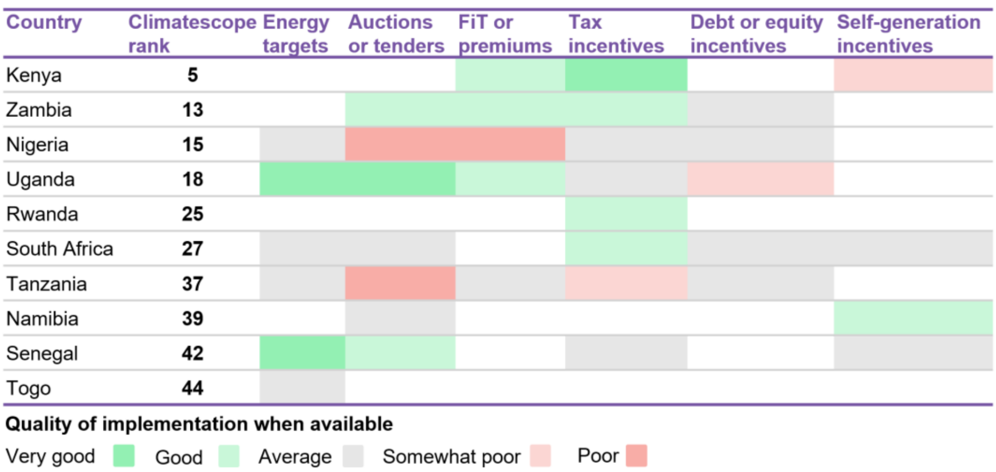
Clean energy is spreading across sub-Saharan Africa, buoyed by policy incentives (Figure 1), donor-backed auction schemes and derisking mechanisms. Overcoming pervasive project risk and a lack of local finance, a number of markets are seeing their first utility-scale solar projects. Yet governments are struggling to afford existing power purchase agreements and will have to make hard choices if they are to find room for renewables.

- Investment in renewables is growing fast – 18 countries received more than $10 million in clean energy funding in 2018, after 23 did so in 2017. That compares to a maximum of 12 countries getting that much annually in the prior 10 years.
- A large pipeline of PV projects is to be built in markets that have little grid-scale solar. Some 1.2GW is expected to come online in 2021 outside of South Africa, more than twice the amount commissioned in 2018.
- Auction programs with multilateral-backing have proven successful. Scaling Solar awarded nearly 0.4GW of PV capacity over 2015-18, or 39% of the total installed outside of South Africa over the same period. But the low tariffs yielded by generous derisking frameworks could lead governments to develop unrealistic pricing expectations.
- Capacity surpluses in several markets belie low plant availability. Even when there is a need for new capacity, offtakers' ability to procure new power can be hamstrung by existing expensive, long-term power purchase agreements. Notably, South Africa and Ghana are both attempting to renegotiate contracts signed with independent power producers.
- Solar home systems, commercial and industrial solar and renewable-hybrid microgrids are growing fast, but require specific economic and policy conditions to be commercially viable.

Figure 1: Policies introduced by top 10 Climatescope scorers in sub-Saharan Africa



Source: Climatescope 2019, BloombergNEF. Note: Climatescope is BNEF's annual survey of investment opportunities in renewables in emerging markets

- Clean energy policies are largely limited to targets and tax breaks, the enforcement of which often leaves much to be desired. Such schemes as net metering and carbon pricing have yet to be effectively introduced outside of a few markets.
- Low hydro availability and a growing reluctance to finance coal will boost investment in renewables in the long run. The ability of gas and coal to compete will also be curtailed by the prohibitive cost of the required infrastructure.
- Interconnection will prove useful for countries struggling to integrate large volumes of variable solar and wind. Three “power pools” have been created in the region to foster the competitive trading of electricity. But all suffer from structural capacity deficits and a lack of investment in transmission infrastructure.
- Offtaker risk remains a central concern to developers across the region. Ailing utilities struggle to improve their finances, and governments often find it hard to raise subsidized retail rates in the face of popular opposition. And while unbundling has proved beneficial in such countries as Uganda, less positive experiences elsewhere show it is no panacea.
- A wide array of instruments allow developers to curtail project risk. All come at a cost. Shielding developers and investors against the possibility of non-payment, various guarantees help make projects viable. Political risk insurance has become standard for large renewables projects, but currency hedges remain too costly to see widespread adoption.

Section 2. Deploying renewables

2.1. LCOEs, investment and capacity additions

The spread of renewables across the African continent owes much to economics. As in the rest of the world, the growth of new investment would be unsustainable were it not for rapidly declining technology costs, making such technologies as PV and wind power competitive against new-build fossil fuels.

Yet sub-Saharan Africa builds less in the way of renewables than any other major region, and clean energy remains more costly to commission and operate than the global average.[1] Emerging markets saw 107GW of clean energy come online in 2018 against just 0.87GW commissioned in sub-Saharan Africa. This is in large part down to currency risk, default risk and a lack of access to finance. However, multilateral-backed support programs and derisking mechanisms have seen investment become ever more geographically diverse.

The cost of solar

The levelized cost of electricity (LCOE) gives an indication of the cost competitiveness of different generation technologies in specific markets.[2] Comparing sub-Saharan African LCOEs for utility-scale solar with the global range is revealing: PV in the region's countries is around 20% more expensive than the regional average (Figure 2).

Part of the story is due to upfront investments being higher in immature markets. For instance, developers in Malawi reported that development costs represented a large share of capex due to long lead times and administrative inefficiencies. Capex is well above $1 million/MW in most sub-Saharan African markets, against BNEF's $800,000/MW benchmark for projects financed in 2019.

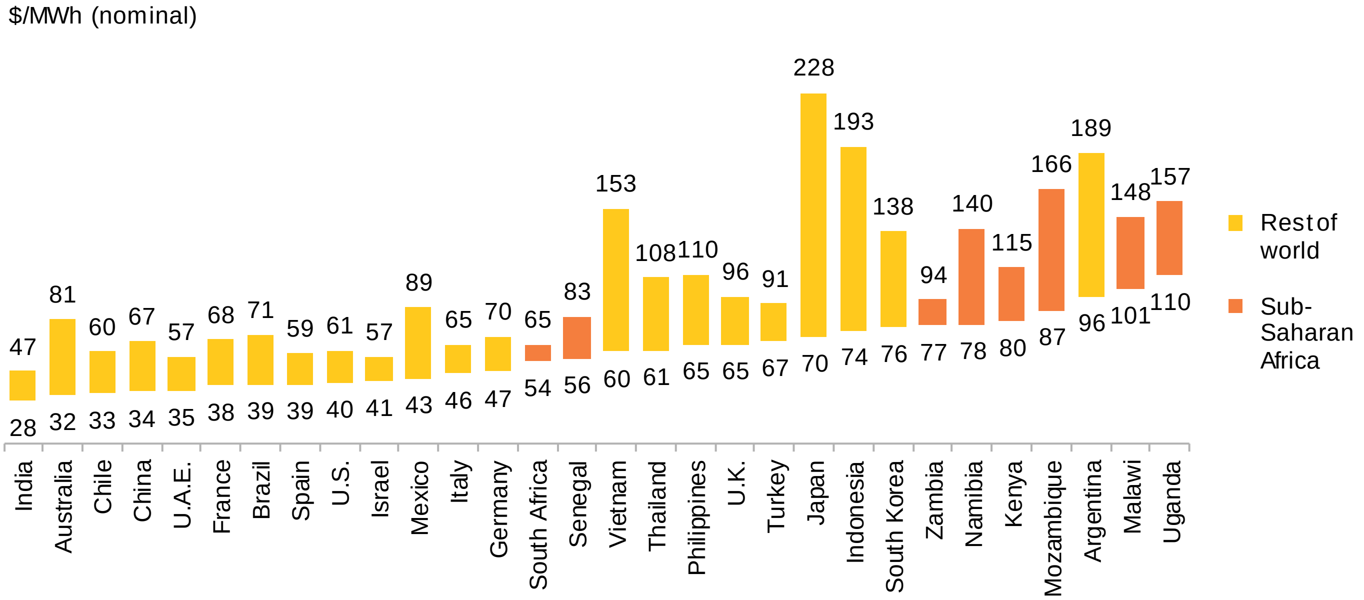
More mature markets generally see lower costs. Such is the case in Senegal, where a pipeline of utility-scale projects going back to 2015 created a favorable environment for new projects. The cost of debt, for its part, varies considerably. Most surveyed projects used concessional debt, rates for which averaged just over 7% in nominal terms, allowing developers to suppress financing costs.

Undertakings without access to concessional rates would likely be far more expensive, a result of pervasive project risk. Moreover, access to cheaper debt is made possible by generous derisking mechanisms available to developers (see *Auctions and derisking*). Generally speaking, the region's good solar resource partly compensates for higher capital costs.

[1] Other regions being Europe, the Middle East and North Africa, Asia Pacific, North America and Latin America.

[2] BNEF defines LCOEs as the long-term offtake price per MWh required for a plant to recoup all costs (capex, opex, interests and tax) and hit investment targets (the hurdle interest rate of return).

Figure 2: Current LCOE range for utility-scale PV ($/MWh, nominal), selected countries



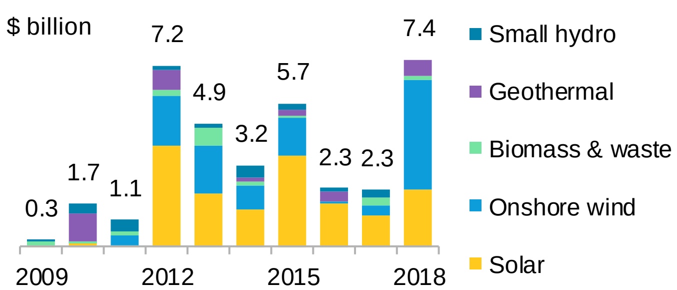
Source: BloombergNEF. Note: LCOE calculations do not account for subsidies. The range captures different costs and resource present in a given market. For sub-Saharan Africa markets, project currency is assumed to be USD with inflation set at 2.8%.

Investment

Investment in renewables in sub-Saharan Africa fluctuates, spiking by nearly 70% over 2017-18 (Figure 3). However, this is because South Africa attracts the vast majority of investment, accounting for over 60% of the total in all years that saw over $4 billion flowing into clean energy (Figure 4). Buoyed by access to local finance, South Africa's renewables sector is the region's largest. Yet policy uncertainty and economic issues have made the market volatile.

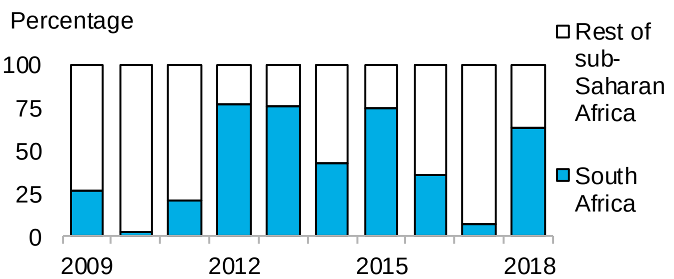
Funneled into a few, large-scale projects, onshore wind investment is lumpy: 2018 saw more than twice the previous record after a lackluster two years. Solar investment is more consistent. The same goes for geothermal, which is mostly in eastern Africa. Biomass and small hydro projects receive only a small share of funding, and offshore wind has yet to be deployed in the continent.

Figure 3: Renewables investment in sub-Saharan Africa by technology



Source: BloombergNEF

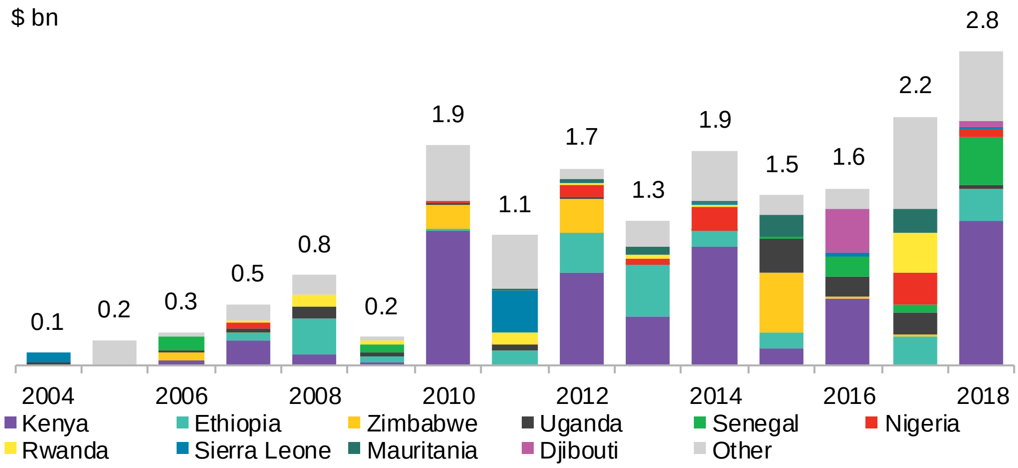
Figure 4: Renewables investment in sub-Saharan according to geography



Source: BloombergNEF

South Africa cannot be overlooked: it accounted for over half of all clean investment in 2009-18. The country saw the third-highest level of finance for new clean energy plants across 101 developing nations in 2018, excluding China/India/Brazil. But sub-Saharan African investment in clean energy excluding South Africa is on a clear upward trajectory (Figure 5). For instance, Kenya accounted for a third of all 2018 foreign inflows in sub-Saharan Africa, recording $1.4 billion in renewables investment.

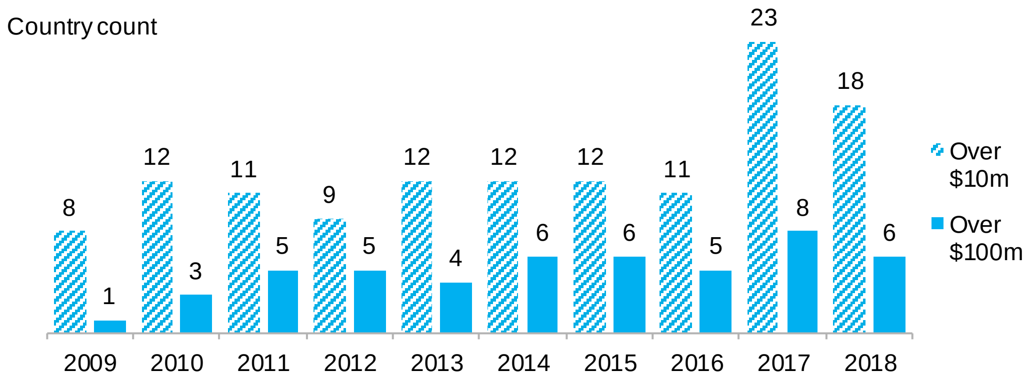
Figure 5: Renewables investment, sub-Saharan Africa excluding South Africa



Source: BloombergNEF

Funding for renewables in the region remains concentrated. But the number of countries seeing significant levels of renewables support is increasing. Some 23 countries received over $10 million of annual renewables investment in 2017, and 18 did so in 2018, against a maximum of 12 countries over the preceding decade (Figure 6).

Figure 6: Volume of renewables investment across sub-Saharan Africa by number of countries



Source: BloombergNEF

Foreign direct investment (FDI) accounted for 47% of sub-Saharan Africa's total clean asset finance for new build over the previous decade and 44% for 2018. A look at its origins reveals several trends. The last 10 years have seen EU member states disburse the largest volumes of FDI – 2018 saw them spend $1.3 billion in the region, reclaiming the top spot lost to Asian investors over the previous two years (Figure 7). Development banks come out as the biggest backers over the last ten years by a large margin (Figure 8).

Figure 7: FDI inflows to renewables projects in sub-Saharan African by region of origin

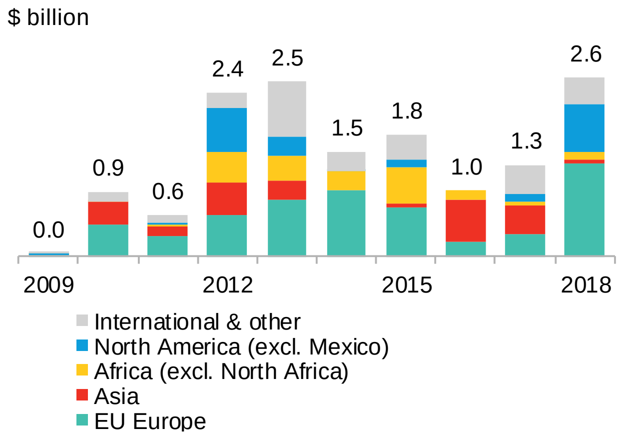
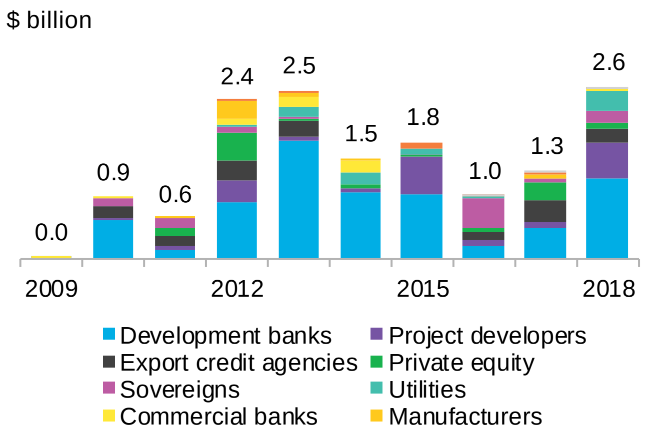


Figure 8: FDI inflows to renewables projects in sub-Saharan African by investor type

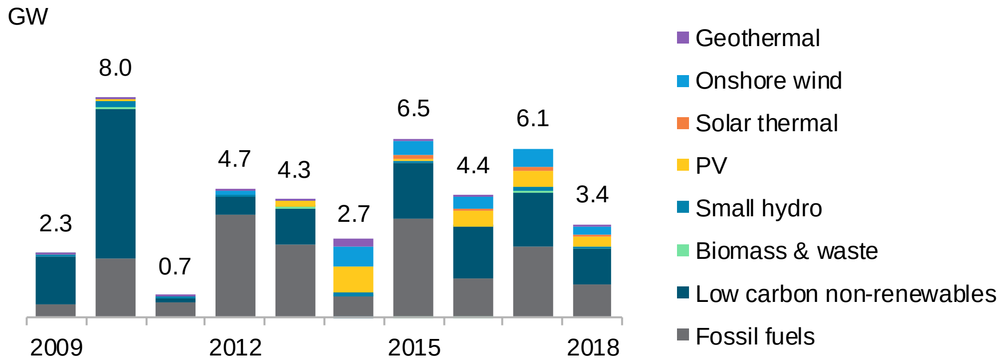


Source: BloombergNEF. Note: FDI data concerns utility-scale asset finance.

Capacity additions

Renewables make up but a small share of new capacity (Figure 9). Large hydro and gas have seen the most growth in recent years. As with clean energy, a select few markets account for an overwhelming share of new non-renewable generation capacity.

Figure 9: Capacity additions in sub-Saharan Africa



Source: Climatescope 2019, BloombergNEF. Note: "Low-carbon non-renewables" refers to large hydro, pumped hydro and nuclear. "Fossil fuels" includes coal, gas, oil and diesel.

PV has grown rapidly in absolute terms since 2010 in markets outside of South Africa (Figure 11). The rate at which new build has progressed is considerably faster than investment, a reflection of global cost reductions driven by technology innovation, economies of scale and manufacturing experience.

The cost of crystalline silicone PV modules has dropped from $2.27/W in 2009 to $0.27 in 2018. The ex-South Africa PV market remains small with around 600MW installed over 2018, but has grown rapidly from a standing start in 2014. Once more, South Africa's higher installation figures vary considerably from one year to the next (Figure 10).

Several promising markets have only seen small-scale or commercial and industrial PV but have sizeable pipelines of grid-scale solar. Kenya alone is predicted to see 220MW of capacity commissioned by 2021 (Figure 11).

Figure 10: New PV capacity additions in South Africa

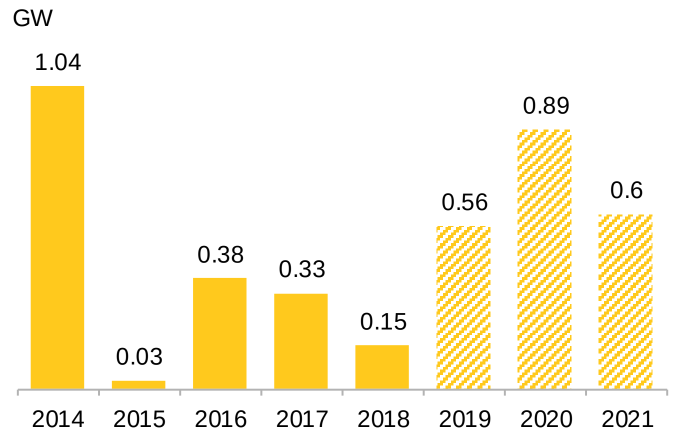
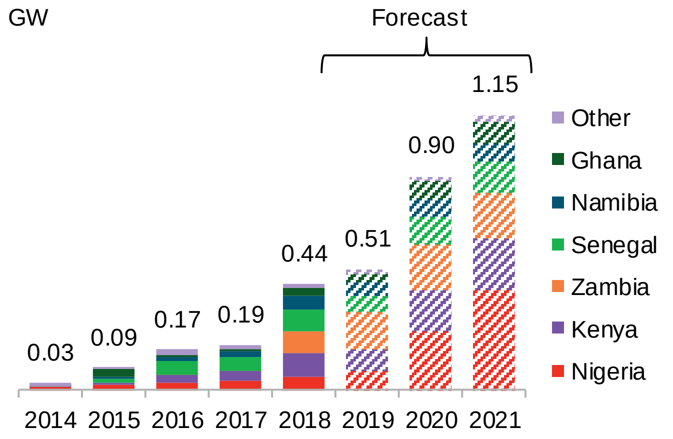


Figure 11: New PV capacity additions in sub-Saharan Africa excluding South Africa

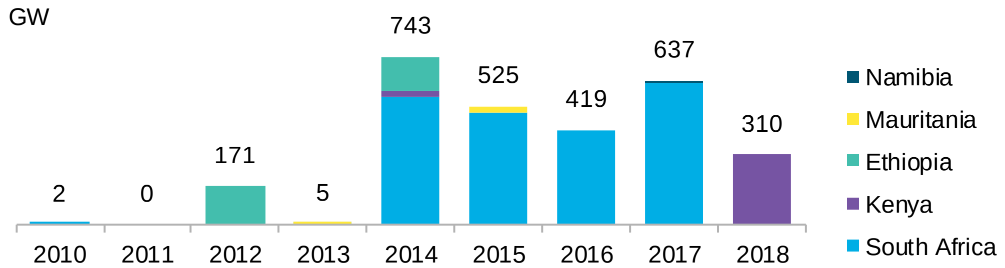


Source: Climatescope 2019, BloombergNEF

On the other hand, only a handful of countries have commissioned any onshore wind capacity (Figure 12). The commissioning of the 310MW Lake Turkana wind farm in Kenya in 2018 was the region's first large-scale wind farm outside of South Africa.

Upon its completion, planned for 2020, the 158MW Taiba N'Diaye project will see Senegal become the next country to bring a large wind farm online. Unlike solar, onshore wind deployment has seen no clear growth since additions peaked in 2014. Facing more challenging grid connection, land acquisition and infrastructure requirements, wind farms must overcome higher hurdles than PV projects.

Figure 12: New onshore wind capacity additions in sub-Saharan Africa



Source: Climatescope 2019, BloombergNEF

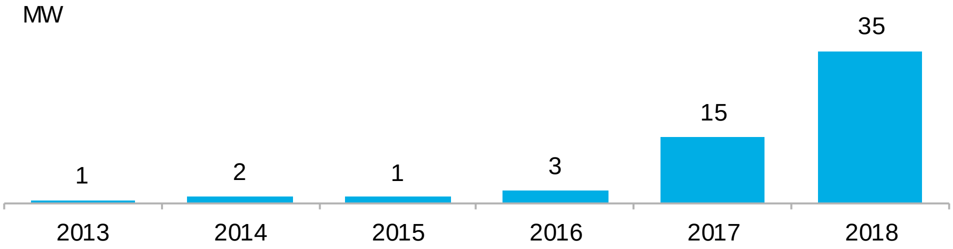
Commercial and industrial solar

Developers are increasingly approaching commercial and industrial customers directly in a bid to secure stronger contracts and shorter lead times

Although the sector has made impressive gains, utility-scale solar's growth in the region has been held back by a number of factors, including unbankable PPAs and long project delays. Developers are increasingly approaching commercial and industrial (C&I) customers directly in a bid to secure stronger contracts and shorter lead times. Only 74MW of C&I solar has been installed across the region (excluding South Africa), and the market remains at an early stage.

The year 2018 saw the most C&I projects installed thus far, with 39 projects amounting to 35MW, against 32 projects totalling 15MW in 2017 (Figure 13). Average project sizes also increased to 1MW in 2018, in large part due to an increasing number of large-scale projects in the mining and manufacturing sectors. BNEF expects 2019 to be another record year.

Figure 13: C&I capacity installed in sub-Saharan Africa



Source: BloombergNEF. Note: Using project data where operation start year was disclosed.

A broad array of factors determine a C&I project's viability. One is how much a customer can save with on-site solar. Average retail electricity prices for commercial customers in 2018 range from \$0.036/kWh in Ethiopia to \$0.199/kWh in Ghana, and \$0.021/kWh to \$0.138/kWh for industrial customers. BNEF puts the cost of a 250kW solar project at \$0.10-0.14/kWh in the countries it has assessed across the region, which happens to be below the cost of power from the grid for commercial customers in a range of countries including Kenya, Senegal, Rwanda and Ghana.

One of the main selling points for C&I solar is the provision of higher quality power than that provided by the grid. The duration and frequency of power outages varies across the continent. Nigeria comes out worst overall in duration and frequency of power cuts. Cuts last 4-15 hours per day on average across the country.

2.2. Renewables policies

Whether due to governments ignoring renewables targets or customs officials playing fast and loose with tax exemptions, policies do not always provide the certainty investors require

Sub-Saharan African energy policy is often described as slow-moving. National climate initiatives, energy plans and power-market reforms often progress at a glacial pace. But the recent introduction of clean energy auctions has opened up clear opportunities for developers looking to enter the region's renewables market. In this area, national policy has been supported by DFI-backed procurement schemes.

A look at countries that scored highly in Climatescope[3] shows how varied success in introducing policies has been across the region (Figure 14). Whether when governments ignoring renewables targets or customs officials ignore tax exemptions, policies do not always provide the certainty

[3] Climatescope is BNEF's annual survey of investment opportunities in renewables in emerging markets.

investors require. Policies that have found traction elsewhere, such as net metering and carbon pricing, have yet to take root outside of a small number of sub-Saharan African markets.

Figure 14: Policies introduced by top 10 Climatescope scorers in sub-Saharan Africa

Country	Climatescope rank	Energy targets	Auctions or tenders	FiT or premiums	Tax incentives	Debt or equity incentives	Self-generation incentives
Kenya	5						
Zambia	13						
Nigeria	15						
Uganda	18						
Rwanda	25						
South Africa	27						
Tanzania	37						
Namibia	39						
Senegal	42						
Togo	44						

Quality of implementation when available

Very good   Good   Average   Somewhat poor   Poor

Source: Climatescope 2019, BloombergNEF

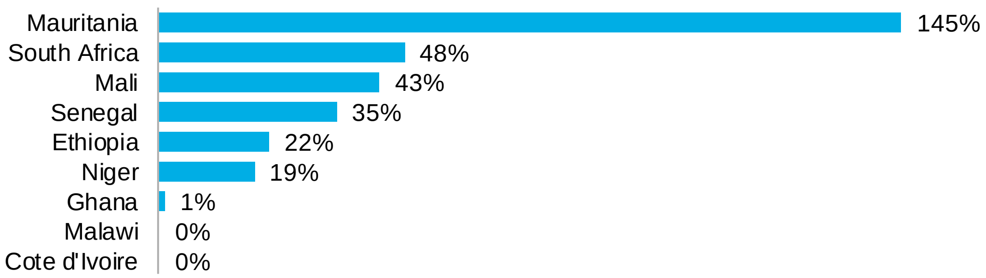
Targets

Nearly 30 sub-Saharan countries, more than half those in the region, have set national renewables targets. These vary from aiming to reach a given share of capacity or generation to installing a certain volume of capacity. In a few cases, they allow large hydro plants to count toward the overall clean energy objective.

Given the region's mixed track-record when it comes to hitting energy targets, investors should approach such policies with a degree of skepticism. A look at the nine countries that had set clear 2020 renewables goals at some point before 2015 is instructive: only Mauritania met its target early, while no other country had hit the 50% mark with only two years to go (Figure 15).

Eye-catching targets are often trumpeted by administrations eager to burnish their green credentials, but an absence of further state support for renewables can render them all but meaningless. This was illustrated by Ghana, where the government's lack of support for clean energy will see it miss its 10% renewables capacity target by 2020 by a sizeable margin.

Figure 15: Progress toward 2020 renewables capacity targets as of 2018



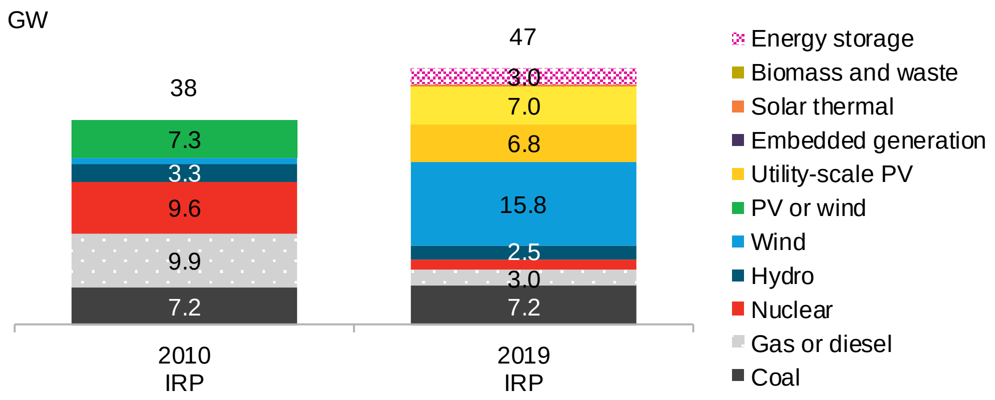
Source: Climatescope 2019, BloombergNEF. Note: Includes both renewables share and absolute capacity targets. Only 2020 targets set by 2015 included.

But some targets represent a government's genuine commitment to building out clean power. Meanwhile, the presence of infrequent, large-scale projects means that apparent laggards can make good on their objectives with a few years to spare. Although its current power mix would suggest that Senegal is far from meeting its renewables goals, the expected commissioning of the 158MW Taiba N'Diaye wind farm in 2020 will see it comfortably exceeding its target.

Targets are made more credible when integrated into detailed energy plans. Some amount to targets in themselves. Such is the case with South Africa's roadmap, the Integrated Resource Plan, whose latest iteration comes almost a decade after the first version was adopted in 2010.

The latest IRP's formal adoption in October 2019 constitutes a sea change in how South Africa plans to ensure security of supply, raising the share of new capacity accounted for by renewables over 2019-30 from 30% to 70% (Figure 16). Storage is also included for the first time, with a target of 3GW by 2030.

Figure 16: South Africa's Integrated Resource Plan for 2019-30 period



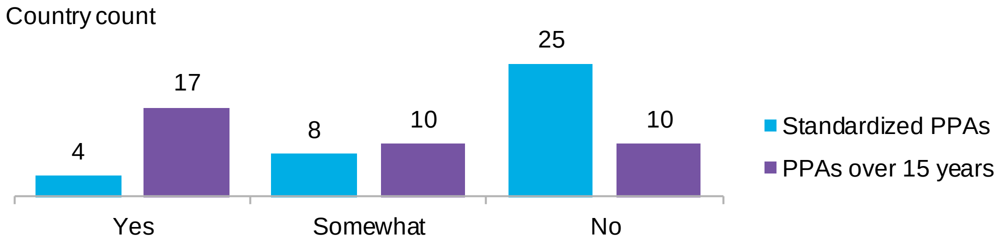
Source: 2010 IRP, 2019 IRP, BloombergNEF. Note: Period 2019-30 includes already-contracted capacity of 5.7GW coal, 1.4GW wind and 1.1GW solar, and excludes the conversion of existing diesel units to gas. Embedded generation in 2019 IRP assumes 3GW supply gap for 2019-22.

Subsidy frameworks

The majority of renewables capacity developed in sub-Saharan Africa has been backed by power purchase agreements (PPAs) between the developer and offtaker. More often than not, payments made to developers for utility-scale projects are disbursed by public entities. Often concluded through ad hoc negotiations following unsolicited proposals, such agreements can be concluded transparently and yield reasonable prices.

Yet contracts negotiated on a case-by-case basis involve high transactional costs. Moreover, they often involve developers negotiating directly with the local state utility, a task for which they tend to be ill equipped. A lack of standardized documents increases development costs (Figure 17). Conversely, utilities often lack the capacity to ensure they are procuring power at a fair price. They often rely on pricing benchmarks set in neighboring countries, even when these are unlikely to be representative of conditions at home.

Figure 17: Clean energy PPA frameworks in sub-Saharan Africa



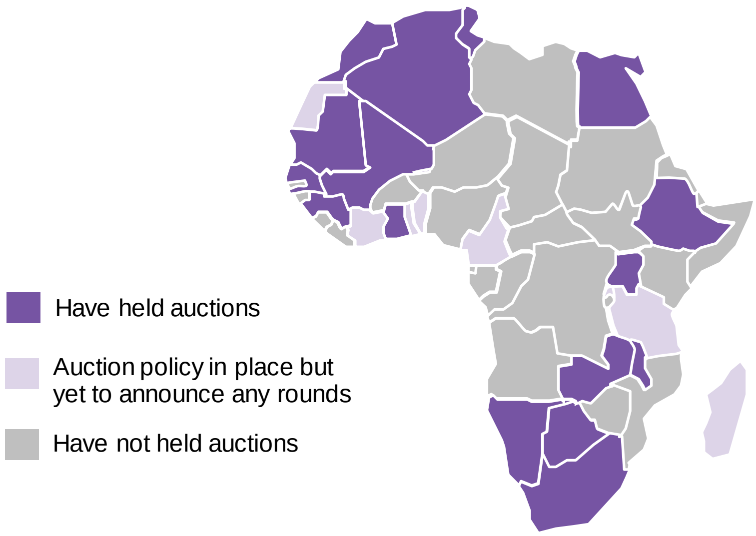
Source: Climatescope 2019, BloombergNEF. Note: "Somewhat" refers to such cases as a PPA framework existing but not having been applied in practice.

Even when competitive tenders are held, those carried out across the continent are often hampered by opacity and arbitrariness

In many geographies, feed-in tariffs were introduced as a means of subsidizing renewables by providing a fixed tariff for each kilowatt-hour fed back into the grid. However, such tariffs were rare in sub-Saharan Africa. Only a handful had such a framework by the time auctions began to see widespread global uptake over 2016-17. Launched in Uganda and Zambia, the REFIT and ensuing GET FiT programs are among the only in the region to have incentivized any meaningful deployment.

Auctions are more administratively complex, and require interest from investors. Moreover, those carried out across the continent are often opaque and ill-managed. But if well-run and attractive to bidders, they can spur competition, driving down subsidy costs in the process. This minimizes the hit to the public purse. Many countries in sub-Saharan Africa have seen their first large-scale renewables projects allocated through competitive auctions at internationally competitive prices (Figure 18).

Figure 18: Renewables auctions in Africa as of 1Q 2020



Source: BloombergNEF

Winning bidders are usually those offering the lowest price. This is the case in most of the continent's major subsidy programs. An alternative approach is taken by small hydro auctions under GET FiT, a renewables auction program that provides a premium on top of a feed-in tariff and has been implemented in Uganda and Zambia. Procurement under GET FiT's small hydro auctions in particular have placed an emphasis on project quality as well as economic value. Projects are awarded according to technical and financial criteria that see qualitative criteria heavily impact bidders' total scores. GET FiT's PV tenders, on the other hand, have been structured to take advantage of the falling cost of solar.

Renewables auctions in sub-Saharan Africa have typically revolved around procuring solar, onshore wind and small hydro. But battery storage is starting to be included. Scaling Solar's first tendering round in Madagascar, currently pending a request for proposals, will award both PV and storage capacity. Similarly, Mali launched a solar-plus-storage auction in August 2019, putting 1.3MW of PV and a 1.5-2MWh of storage out to tender.

Auctions and derisking

Many ongoing auction schemes include derisking measures (Table 1). This is particularly the case for DFI-backed auction programs, whose risk-mitigation measures are more comprehensive that those that typically accompany tenders held in more mature renewables markets.

Table 1: Auction schemes in sub-Saharan Africa

Scheme	Countries	Generation technologies	Capacity allocated	Land and grid connection risk borne by	PPA tenors
REIPPP	South Africa	PV, solar thermal, biomass, onshore wind, small hydro, landfill gas	6.38GW since 2011	Developer	20 years
GET FiT	Uganda, Zambia, Mozambique*	PV, small hydro, biomass, biogas	0.28GW since 2013	Developer	20-25 years
Scaling Solar	Zambia, Senegal, Ethiopia, Madagascar, Togo*, Cote d'Ivoire*	PV	0.44GW since 2015	Government	20-25 years

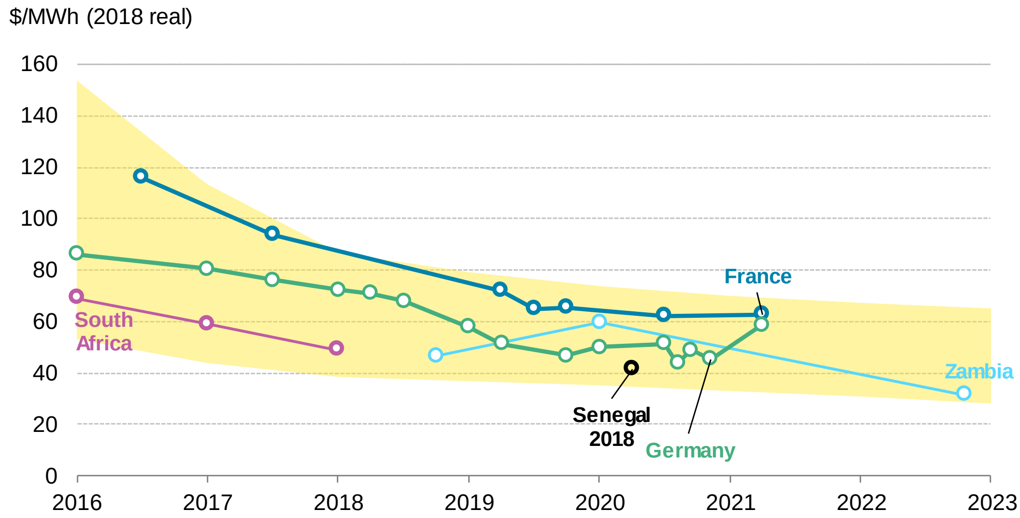
*Source: BloombergNEF. Note: Connection risk is defined as developers being responsible for bearing the cost of connecting the generation plant to the nearest substation. GET FiT also provides access to feed-in tariffs for certain technology types. *Countries in which auctions have been announced but have yet to be launched.*

One of most high profile examples is the World Bank's Scaling Solar program, present in six sub-Saharan African countries. The program's derisking measures include presecured project sites, standardized contracts and a range of guarantees. Taken as a whole, the package is designed to simplify project development, shorten lead times and attract investment.

Similar tools are part and parcel of the region's other two main auction programs: GET FiT and South Africa's REIPPP. As with most subsidy schemes, all three programs involve standardized documentation, removing the need to individually negotiate PPAs. More importantly, each provides some form of guarantee, ensuring that the government will back contracted payments in the event of such eventualities as the offtaker defaulting.

Removing risk means that such projects have benefited from lower financing costs, which are further reduced by the presence of concessional debt. Auction programs such as these have bagged some of the world's lowest auction bids, showing that projects can be developed in the region at rock-bottom costs (Figure 19).

Figure 19: Weighted average results of select EMEA PV auctions (by commissioning date), and LCOE range for the region



Source: BloombergNEF

Programs differ in the support they provide to developers. Unlike winning bidders in Scaling Solar, developers participating in GET FiT and REIPPP must acquire their own sites and pay for a grid connection. The prices reached in both auctions are more likely to be representative benchmarks of in-country development costs as a result. But their scope is more limited than Scaling Solar: REIPPP is only run in South Africa whereas GET FiT has awarded no more than 280MW since its inception in 2013.

Auction implementation

The handful of auctions held across sub-Saharan Africa have produced some of the world's lowest prices, proving that competitive prices can be achieved outside of South Africa (Figure 19). This shows that, despite considerable country risk, the viability of projects in the region need not depend on sky-high tariffs.

By addressing many of the hurdles that have stymied the development of utility-scale renewables, auctions have proven an effective means of driving clean energy's progression across the continent. Derisking frameworks such as Scaling Solar will likely prove key to creating local value chains, developing investor-attracting reference projects and, in the long run, involving local finance. But weaning the sector off relying on such mechanisms will be a slow, iterative process.

Without implicit subsidies, auction bids would be much higher than those seen in more mature markets

Lower bid prices are a result of clean energy's increasing maturity and sinking technology costs. Yet the level of support accorded to developers should not be overlooked. Without such implicit subsidies, auction bids would be much higher than those seen in more mature markets such as Germany, where developers take on far more project risk. This can skew governments' expectations, leading to policy makers demanding unrealistic prices for projects that have a higher risk exposure. Most developers interviewed by BNEF echoed such concerns.

Moreover, placing the burden of site acquisition on the government can be counterproductive. Comparing PV projects developed within and outside of the Scaling Solar program in the same country, developers told BNEF that site acquisition had been swifter when carried out internally.

State utilities were reported to be taking several months longer to secure land than would otherwise have been expected.

But land risk varies across different geographies, as measures to tackle site acquisition vary across markets. Unlike previous iterations, GET FiT's forthcoming expansion to Mozambique will likely see sites being identified before projects are put out to tender. This is due to concerns regarding land issues.

The introduction of auctions constituted a learning process. While an overall success as one of the region's first auctions, the initial GET FiT program, launched in Uganda in 2014, encountered several issues. For one, transaction costs were such that tenders lent themselves to mid-sized-to-large projects. Substantial resources were devoted to developing small projects, many of which were bagasse and small hydro under 10MW.

Performance issues and requests for design changes after project approval caused numerous project delays. As a response, the GET FiT Secretariat has moved to specify higher technical standards and requirements for proposals submitted by developers. Further steps included introducing punitive subsidy reductions and, starting in 2019, quarterly inspections of sites under development. Developers are also required to keep records regarding mandatory maintenance which are to be provided when applying for annual subsidy payments.

Issues of a different nature have affected Scaling Solar's first round in Ethiopia, results for which were announced in mid-September 2019. Saudi Arabia-based ACWA Power was awarded two PV projects of a combined 250MW for $25.20/MWh, Africa's lowest bid price to date. That both projects were handed to the same developers ran contrary to the auction's rules. The original terms stated that the two had to be allocated to different developers, with both bidders invited to match the lowest price if one developer had placed the lowest bid for both.

Following a dispute between the Ethiopian Central Bank and the IFC over the risk allocation of currency convertibility, the IFC had also withdrawn a pre-approved term sheet several days before the tender's launch. Four bidders that had included IFC-stapled financing in their submissions were disqualified. No announcement has been made by the IFC since the final bids were submitted. This may deter participants in Ethiopia's second round of Scaling Solar auctions, request for proposals for which are currently pending.

Tax exemptions

Besides targets, the most widespread policy instrument in the region involves governments waiving the tax levied on certain renewables equipment classes (Table 2). While less costly and simpler to implement than other subsidy types, foregoing fiscal revenue can deprive state coffers of substantial funds, if clean energy is rolled out at scale.

BNEF found that 23 sub-Saharan countries had implemented such policies, including import duty exceptions and freeing developers from paying value-added tax on certain components. This includes the East Africa Community (EAC)[4], which lifts import duties from solar panels and batteries to be used for PV projects. Broadly speaking, most fiscal incentives favor utility-scale solar – wind and small-scale PV equipment are often subject to the normal tax rates.

[4] The EAC includes Burundi, Kenya, Rwanda, South Sudan, Tanzania and Uganda

Table 2: Tax exemptions for PV equipment

Import duty	Countries	VAT rate	Countries
0%	Angola, Botswana, Burkina Faso, Chad, Cote d'Ivoire, D.R.C, Ethiopia, Ghana, Guinea, Liberia, Malawi, Mali, Niger, Sierra Leone, South Africa, Togo, Zambia, Zimbabwe, EAC countries	0%	Angola, Benin, Botswana, Burkina Faso, Burundi, Chad, Guinea, Kenya, Rwanda, Sierra Leone, Madagascar, Mali, Togo, Zambia
1-5%	Benin	1-5%	Liberia, Mozambique, Cameroon, South Africa
6-10%	Cameroon, Madagascar, Mozambique	6-10%	South Africa, D.R.C., Zambia, Malawi, Burkina Faso, Mali, Tanzania, Uganda, Niger, South Sudan
11-15%	Eritrea, Nigeria, C.A.R.	11-15%	Eritrea, Senegal, Madagascar, Ethiopia, Benin, Somalia
16-20%	Namibia, Lesotho, Senegal, South Sudan	16-20%	Mauritania, Cameroon, Cote d'Ivoire, Nigeria, Namibia, C.A.R., Lesotho, South Sudan, Sudan, Ghana, Zimbabwe, Congo
21-25%	Sudan	21-25%	Somalia
26-30%	Congo, Mauritania, Somalia	26-30%	None

Source: Climatescope 2019, BloombergNEF

Yet the relative ease with which tax breaks can be deployed is double-edged. Governments often repeal such incentives once renewables build ramps up, increasing the value of the foregone tax take. The EAC, for instance, tightened exemptions in 2016, removing tax waivers on a range of solar components other than modules and batteries.

Rules governing taxation are often reviewed annually. That can deprive developers of visibility into the mid-term and increaser uncertainty regarding development costs. What is more, a lack of awareness of such incentives can damp their effect. In South Africa, accelerated depreciation allowances were introduced in 2016, minimizing the fiscal burden imposed on solar projects under 1MW. But the updated income tax legislation has not been made available on the official revenue service portal.

When solar is targeted, components that do not serve for generation are not usually exempt. Many solar home system companies argue that appliances that come with their kits – including lanterns, televisions and sewing kits – should benefit from similar tax breaks. Yet try as such actors may, such lobbying often falls on deaf ears. Such is likely to be the case in Senegal, which is unlikely to include such equipment when it enacts new tax exemptions in 2020.

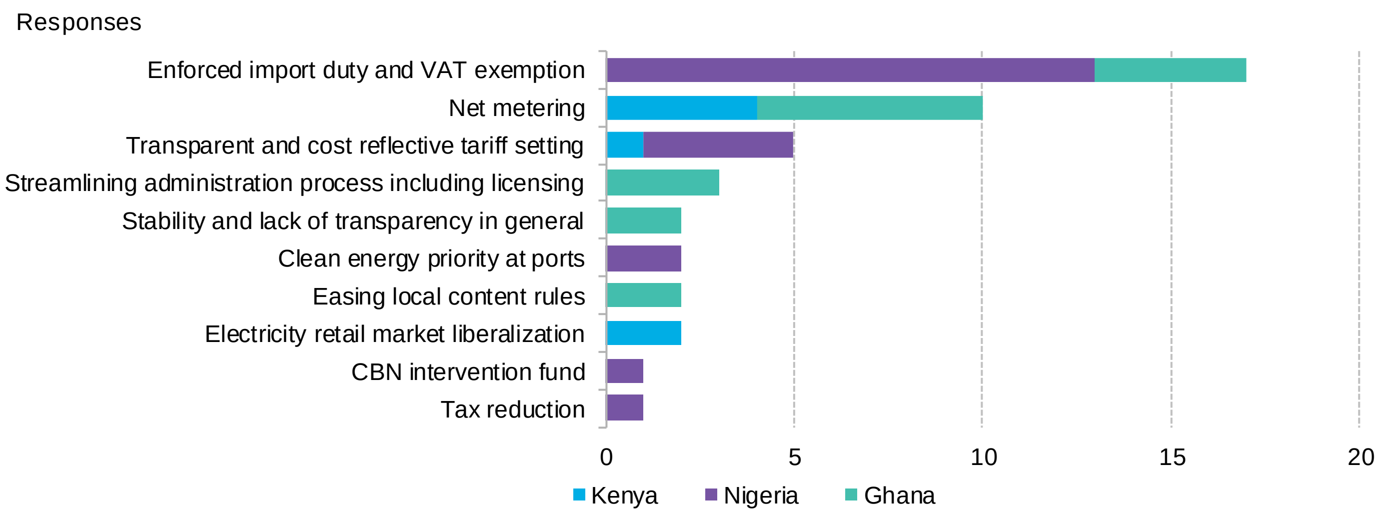
Inconsistencies often arise at the border. Although batteries and solar equipment are exempted from import duties in Uganda, such is not the case for separately shipped batteries that are to be combined with solar. Many markets, including Cote d'Ivoire and Ethiopia, see import exceptions routinely ignored by customs officials.

Net metering

Net metering allows system owners to funnel excess power back to the grid, subtracting its value from their retail bills. Without net metering, the size at which installations are economically viable is constrained by the need to maximize how much power is consumed. This is relevant to households and most businesses, both of which consume less during the weekend.

Net metering schemes can help incentivize C&I solar: in a survey carried out by BNEF in 2019, net metering was ranked the second most desired regulatory reform by companies active in the C&I space in Kenya, Nigeria and Ghana (Figure 20).

Figure 20: Regulatory reforms desired by C&I solar business players



Source: BloombergNEF. Note: We asked if the current regulation is implemented as it should be and what regulatory reforms are needed, and collated answers from 29 respondents. Responses are cumulative and include all the reforms they listed in the interviews. CBN = Central Bank of Nigeria.

But net metering policies are few and far between in the region. South Africa has seen some uptake at a municipal level. While a national net metering program has been suspended, a number of local authorities oversee schemes.

Namibia published tariffs for net metering in 2017. Its scheme has been criticized by municipalities, which are loath to see net metering offset centralized power purchases, a significant source of municipal revenue. But a recent jump in the number of rooftop solar projects and the presence of numerous companies specialized in rooftop solar suggest that the scheme has been successful.

There are several cases of new net metering regulations failing to encourage uptake. For instance, Ghana introduced a net metering framework over 2015-16, but further progress was hindered by opposition from distribution utilities. The country has yet to pass a net metering law. Countries considering introducing legislation include Kenya.

The first such policy in sub-Saharan Africa, South Africa's Carbon Tax Act, came into force on June 2019

Senegal passed a net metering law in October 2018 – a pilot project has been launched. Targeting urban areas, the scheme sees a tariff being paid for all excess, self-generated energy over a 20-year period. The policy will offer tariffs of $0.086-0.129/kWh. While heavily subsidized, that state utility Senelec's tariffs are higher than the average in sub-Saharan Africa could make the program more attractive to consumers.

Pricing carbon

Pricing carbon that is emitted can incentivize the deployment of renewables. The first such policy in sub-Saharan Africa, South Africa's Carbon Tax Act, came into force in June 2019, covering road transport, industry and power. The starting allowance price imposed on companies is low at

120 rand/MtCO2 ($8.21), and its impact is further limited by various tax breaks. These allow big emitters to pay 6-48 rand/MtCO2 ($0.41-$3.28). That compares to such schemes as the EU Emission Trading System, which stood at 24.44 euros/MtCO2 ($27.14) in early December. How the scheme's proceeds are to be used has yet to be confirmed.

Although initially opposed by state-owned utility Eskom, the scheme's allowance pricing is currently too low to radically change polluters' behavior. Moreover, in the absence of a wholesale electricity market, its impact on the power sector is damped. But allowance prices are set to rise – the scheme's second phase will see a higher tax imposed from 2022.

Several sub-Saharan African countries are considering implementing similar plans, including Senegal and Cote d'Ivoire. Senegal's government organized consultations on a national emissions trading scheme with stakeholders in 2018, commissioning a study that was published in the same year. Both have yet to submit a legislative proposal to price carbon, however.

Local content

Local content rules, which limit the share of foreign-manufactured equipment that can be used for projects, are controversial. Backers argue that they can help build up local value chains. Detractors, however, decry them as market distorting. Restrictions on imported equipment raise upfront capital costs, which are a larger share of costs for renewables than for fossil fuels.

The impact of such rules depends on a variety of factors, such as having a large enough market to nurture domestic value chains to maturity. But few countries have a project pipeline that can incentivize production. Investment in such facilities as turbine plants is only feasible in countries with major procurement programs. On the other hand, such equipment types as solar inverters face a lower barrier to in-country manufacturing.

Ghana enacted new local content rules in early 2018. They call for over half of value across project development to go to Ghanaian-owned companies and high levels of local content for solar and wind equipment. Local content for photovoltaic panels, for example, is to reach 90% (Table 3). Non-Ghanaian companies that were operating before December 2017 have a five-year grace period to comply. Regardless of the presence of manufacturing facilities such as a 30MW module plant, the new regulations will raise project costs and deter investors.

Table 3: Renewable energy local content targets, Ghana

Item	2020 local content level	2025 local content level
Solar cell	50%	80%
Storage system	80%	80%
Photovoltaic panel	80%	90%
Inverter	80%	100%
Wind turbine	80%	100%

Source: BloombergNEF, Ghanaian Energy Commission

Concern has also surrounded the role of local content rules in South Africa's renewables procurement program, REIPPP. The minimum threshold imposed in previous rounds was set at 40-45%. But a three-year lag since the last procurement round has caused much of the industrial activity stimulated by the policy to stagnate, leading to bankruptcies among domestic solar module manufacturers. The auction's fifth round has yet to be announced, but there is a high likelihood that already-substantial local content criteria will be tightened.

The REIPPP's local-content requirements have, however, fostered the growth of South African IPPs as well as manufacturers. A number of home-grown players are active in auctions outside the country, as in the latest GET FiT auction in Zambia, the results for which were announced in April 2019. But backers are starting to oppose such schemes. The European Investment Bank announced that it would limit its support of the REIPPP program, arguing that local content contravenes EU competition rules.

Section 3. Broader power sector

3.1. Gas, coal and large hydro

Several non-renewable technologies dominate the region's power fleets. Some are seeing steady investment: a large number of gas, coal and large hydro projects are planned across the region.

However, their outlook is dimmed by several factors. Financiers are increasingly reticent to put money behind coal. With time, gas plants and infrastructure are likely to be exposed to a similar trend. Moreover, the cost of such natural gas infrastructure as pipelines restricts deployment. And with more frequent, longer droughts on the horizon, the wisdom of investing in new large hydro plants sited on water-stressed river basins is questionable.

Gas

Sub-Saharan African countries added 8.7GW of gas capacity over 2000-2018 – only large hydro saw greater additions, at 15GW. New build has been highly concentrated – Nigeria alone accounted for 5.8GW (Figure 21). Unlike large hydro but similarly to renewables, most new gas plants are operated by independent power producers.

Figure 21: Installed gas capacity per country

Source: Climatescope 2019, BloombergNEF. Note: Only includes countries with gas fleets of 200MW or above.

The last decade has seen a series of major gas discoveries made in Mozambique, Tanzania, Senegal, Mauritania and South Africa. The knock-on effect on national power sectors varies. Under certain circumstances, a ready supply of domestic gas might reduce the government's commitment to supporting renewables.

Such has been the case with gas giants such as Nigeria and Ghana, where abundant gas reserves mean less official interest in utility-scale renewables. But continued development means moving into deeper gas fields, raising extraction costs. Moreover, developing discoveries requires favorable investment conditions, a lack of which has made tapping into Tanzania's reserves slow going.

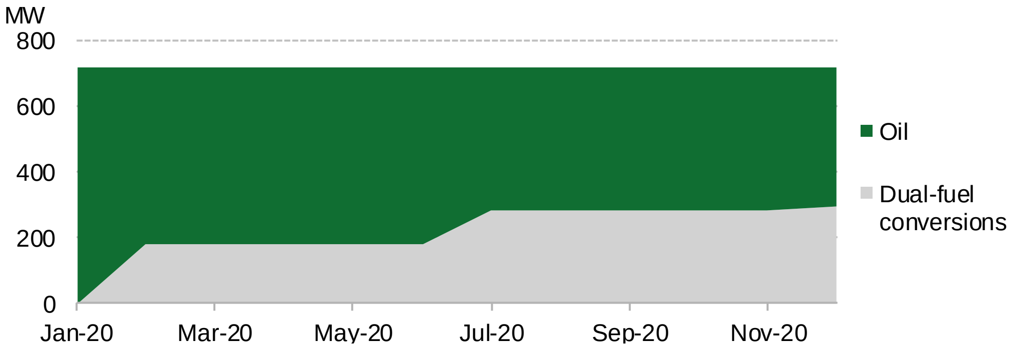
Many developments are geared toward gas exports. Such is the case in Mozambique, where developing discoveries made in 2010 will likely feed new gas plants as large as 2GW. This could be arranged by liquefying and regasifying domestic gas, or through a $6 billion pipeline stretching 3,000 km to southern demand centers and South Africa.

There are doubts as to whether the available market are sufficient to render the Mozambican project economical. Such concerns are also present in Ghana, where there are doubts as to whether new gas developments can be linked to eastern demand centers. The cost of pipelines is often prohibitive when the associated demand is low.

Senegal's reserves are to be developed more swiftly. The largest of its two gas fields, Grand-Tortue, is to see first gas in 2022-23. An export strategy is being aligned with a pivot toward gas-fired generation. Costly, imported heavy fuel oil and diesel accounted for over 60% of installed capacity in 2018.

The current administration has developed a strategy to convert state-owned utility Senelec's oil-fired power stations to dual-fuel (Figure 22), an approach also being explored in Kenya and South Africa. Senegal's government is planning to build new combined-cycle gas turbines (CCGT). It is considering starting with a 500MW plant on the border with Mauritania, which also enjoys large gas fields.

Figure 22: Planned conversions of Senegalese oil-fired power plants to dual-fuel



Source: Ministry of Oil and Energy, Senelec, BloombergNEF

Adding gas plants will help balance the large volumes of solar and wind added since 2016. Together, the new projects will see Senegal overshooting its target of 15% of renewable energy in generation by 2025, five years ahead of schedule. But in the short term, the focus will be on building out gas generation over clean energy.

Senegal's as-of-yet unpublished 2019-23 energy plan sees no new solar or wind capacity coming online over 2020-23, while gas is to be increased by nearly 90% to 184MW. But that will still be less than the 386MW of clean power predicted to be online in 2023. Grid-scale renewables deployment will pick up again in the mid-term as demand continues its upward trajectory: peak load rose from 424MW to 640MW over the decade to 2018 and is expected to keep growing.

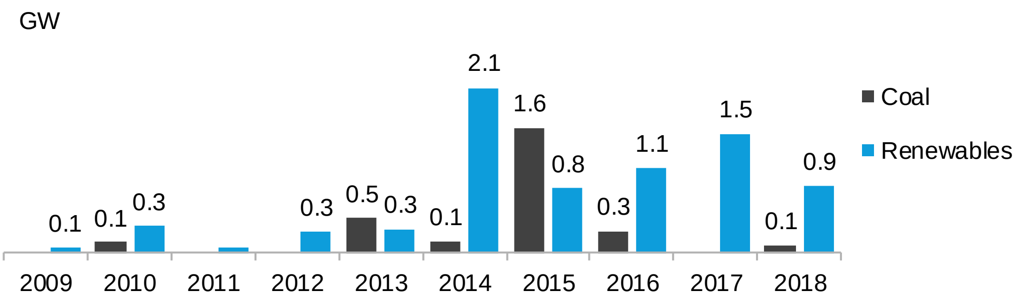
Take-or-pay contracts seem poorly adapted to remunerating plants that are to be rapidly dispatched for short periods

As is reflected in South Africa's new energy roadmap (see *Targets*), continuing renewables deployment will lead to lower load factors for fossil fuel plants, reducing the business case for new baseload CCGT capacity. Gas peakers could play an important balancing role as renewables are added. But take-or-pay contracts, which provide the basis for most gas IPPs, seem poorly adapted to plants that are to be rapidly dispatched for short periods.

Coal

Public and DFI funding continue to flow into coal projects. Yet countries in sub-Saharan Africa have installed nearly three times more renewables than coal over the last decade, with more clean energy additions beating coal in each of the last ten years (Figure 23). Nevertheless, a large pipeline of coal plants remains under development.

Figure 23: New renewables and coal capacity additions in sub-Saharan Africa

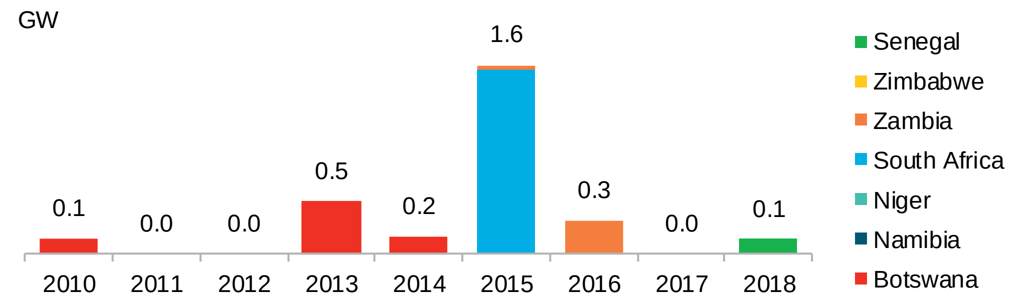


Source: Climatescope 2019, BloombergNEF

For the most part, coal plants are concentrated in southern Africa. South Africa, whose coal reserves are the region's largest, accounts for 94% of installed coal generation capacity in sub-Saharan Africa. Niger's 36MW of coal was the only tranche in operation outside the continent's south until the completion of a 125MW Senegalese plant in 2018.

Coal imports and the associated infrastructure are costly. Even costly diesel and heavy fuel oil imports often offer a better value proposition in countries without large coal reserves, leading to new coal plants remaining concentrated in southern Africa (Figure 24).

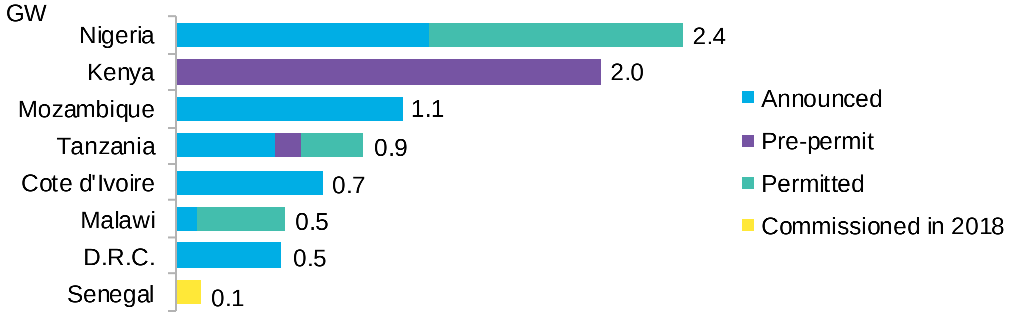
Figure 24: New coal capacity additions in sub-Saharan Africa according to country



Source: Climatescope 2019, BloombergNEF

But some countries are seeing their first coal plant (Figure 25). Several are keen to add to existing coal fleets of under 1GW. Others, such as a 700MW Ivorian plant whose commissioning is tabled for 2021, will likely run on expensive South African coal imports. It is far from clear how many of the planned projects will be seen through, but issues associated with recent projects suggest that many will go undeveloped.

Figure 25: Coal projects in sub-Saharan African, countries with no installed coal capacity



Source: Global Energy Monitor, BloombergNEF. Note: Data last updated in June 2018. Only includes countries with coal project pipeline of at least 500MW.

The AfDB said in November 2019 that it will not finance new coal plants in the future

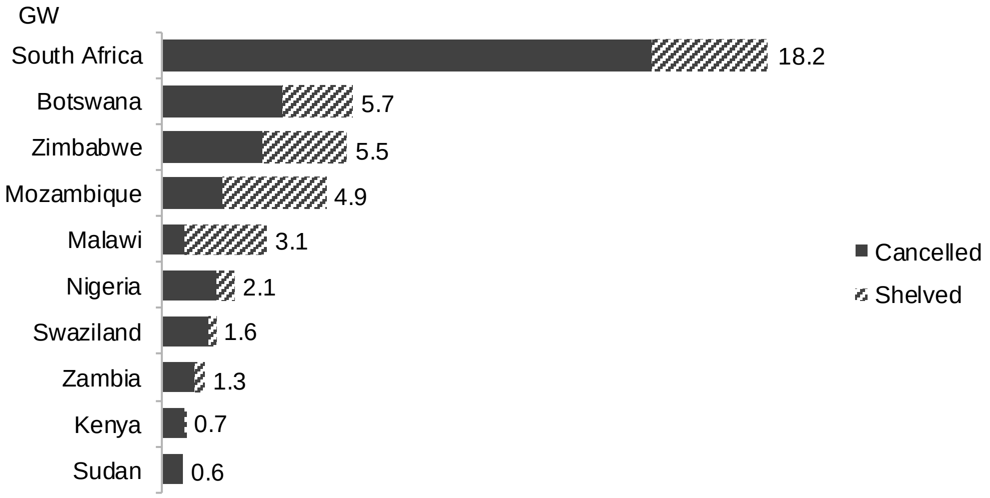
Investors backing such projects vary, but two sources of finance stand out: MFIs and Chinese backers. But potential credit providers are getting cold feet. The African Development Bank (AfDB), for its part, announced in November 2019 that it will no longer finance new coal plants. The European Investment Bank has made a similar declaration, saying it would no longer back unabated oil, gas and coal generation projects after 2021. The coming years will likely see other lenders following suit, freeing up credit for renewables projects.

Meanwhile, South Africa's largest banks are restricting lending to coal mining, with financiers driven off by the risk of future climate policies stranding investments. In the same vein, South Africa's biggest three banks – Standard Bank, FirstRand Bank Ltd. and Nedbank – all imposed more stringent requirements on financing new coal.

Over the course of 2019, all three banks withdrew funding for two coal plants under construction – the 557MW Thabametsi and 306MW Khanyisa projects. Developers are also pulling out of projects still in planning: Japanese conglomerate Marubeni Corp. withdrew from a proposed 300MW extension to a Botswanan coal plant in October.

Concerns regarding plants becoming stranded assets have contributed to South Africa shelving or cancelling over 18GW of coal plants over 2010-19 (Figure 26). This reflects a decrease in the global pre-construction coal pipeline, which has declined every year since 2015, according to Global Energy Monitor. Economics also matters – the plummeting cost of renewables will keep coal from catching up with clean energy additions.

Figure 26: Coal plants shelved and cancelled



Source: Global Energy Monitor, BloombergNEF. Note: Refers to 2010-19 period. Shelved indicates projects whose development has been halted in the absence of a definitive cancellation.

Local acceptance issues further worsen coal's outlook. For instance, construction of Kenya's Lamu plant was initially expected to start in 2015. The coal burner, predicted to come at a cost of $2 billion, would be eastern Africa's first, adding just over 1GW of baseload capacity to Kenya's 2.8GW power system. But the project has been dogged by repeated delays

While the plant's coal was originally to be sourced from a mining basin over 300km away, the lack of domestic infrastructure means that coal would be shipped from Botswana or South Africa, increasing costs. It was also assumed that the project's capacity factor would be around 85%. However, the current power mix will likely lower it to 60%, further hurting the project's case.

Uniting under the "Save Lamu" coalition, community groups rallied against the plant, citing environmental concerns and the project site's UNESCO heritage status. Development was stopped after a Kenyan court invalidated the project's environmental impact statement on July 11. A new assessment is due by February 2020.

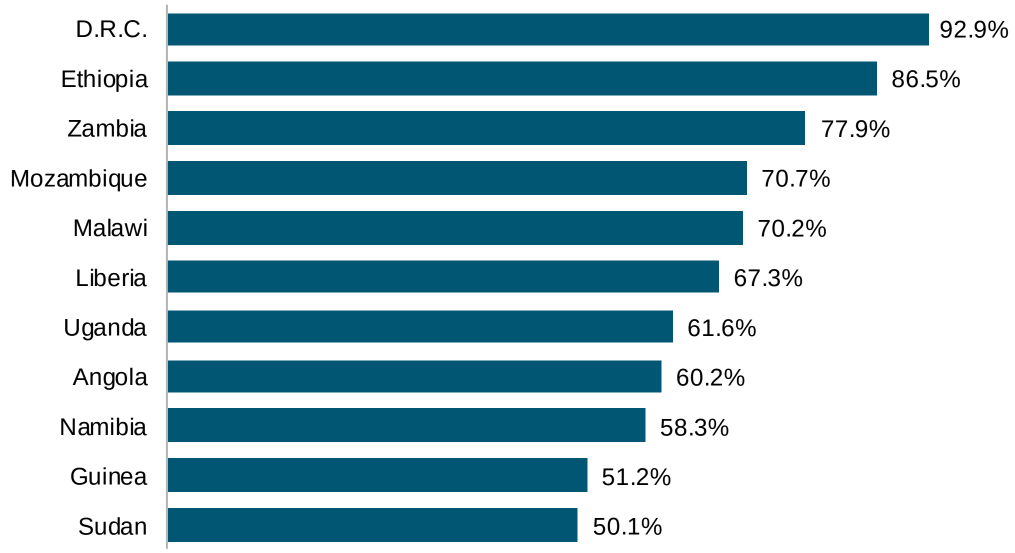
A further setback struck while the project was in limbo. The AfDB – which had agreed to provide $1.2 billion in finance – announced that it was both pulling out of the project and would no longer be financing coal assets on November 13. China's Industrial Commercial Bank and General Electric remain among the plant's backers.

Large hydro

Unlike coal and gas, much of sub-Saharan Africa relies on large hydro[5], which accounted for at least half of the total installed capacity in 11 countries in 2018 (Figure 27). Providing long-term sources of baseload power with low running costs for up to a century, mammoth dam projects rank among the continent's largest energy undertakings. Sited on waterways that snake over multiple borders, some plants have served as starting points for crossborder power trading (see *Interconnection and power pools*).

[5] Large hydro refers to hydroelectric installations of a capacity of at least 50MW.

Figure 27: Large hydro as a share of installed capacity, 2018



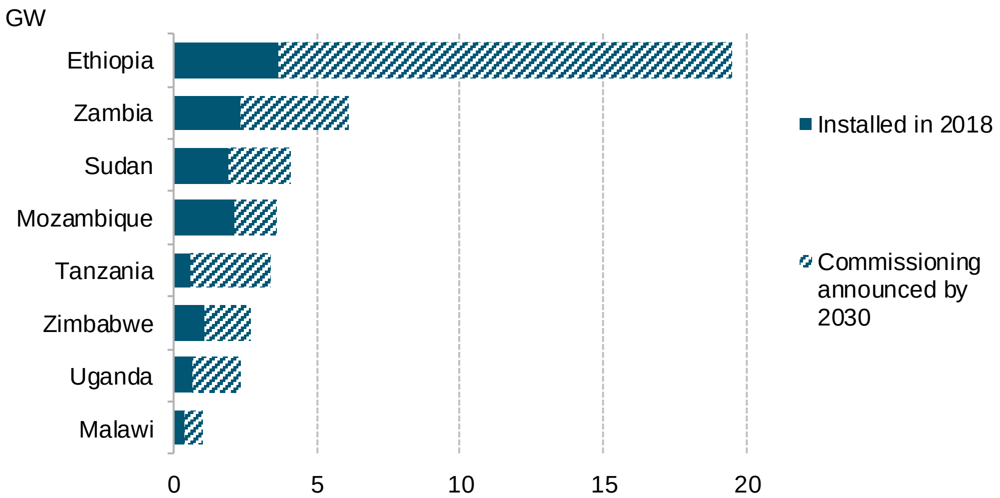
Source: Climatescope 2019, BloombergNEF. Note: Includes countries where large hydro represents over half of installed capacity.

Having access to long-term sources of clean, dispatchable power with rock-bottom marginal costs can slow the spread of renewables. But recent years have seen droughts take their toll. Difficulties in predicting hydrological cycles, temperature and precipitation patterns have upped the stakes, casting doubt on large hydro's ability to ensure security of supply.

Bunching projects on a single basin increases their vulnerability to varying rainfall. But the Grantham Research Institute found that 89% of southern Africa's planned large hydro pipeline is to be sited on the Zambezi, which flows through six southern Africa countries (Figure 28).

Predicting that much of sub-Saharan Africa will experience worse and more frequent droughts in the coming decades, the International Panel on Climate Change noted that, of Africa's 11 major basins, the Zambezi was that most likely to be negatively affected by climate change. Meanwhile, some 82% of new large hydro capacity in eastern Africa is to be built on the Nile, on which Ethiopia hopes to construct a number of new dams.

Figure 28: Large hydro capacity, installed in 2018 and planned by 2030

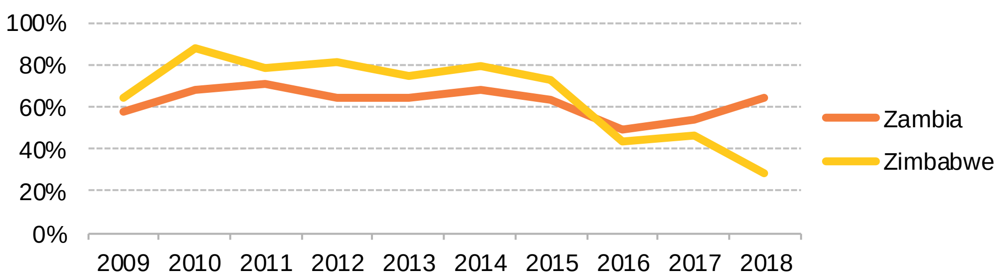


Source: Grantham Research Institute, Climatescope 2019, BloombergNEF. Note: Plans as of August 2018.

Zambia and Zimbabwe exemplify the issues faced by hydro-dependent nations. Some three-quarters of Zambia's installed capacity is large hydro, and the technology accounts for 44% of Zimbabwe's fleet. A dry spell over 2015-16 caused large power deficits (Figure 29), leading Zambia to accumulate $6 million in debt to Eskom for emergency power imports. In 2019, Zambia again suffered a drought, one of its worst since 1981. Outages spiked as state utility Zesco struggled to eke out what power it could.

High as it remains, the share of large hydro in Zambia's installed capacity decreased from 95% in 2000 to 78% in 2018. The country has a sizeable renewables pipeline as it strives to diversify, notably awarding 210MW of PV through various auction programs (see *Subsidy frameworks)*. However, growth in clean energy is overshadowed by such new large hydro plants as the 2.4GW Batoka Gorge project.

Figure 29: Zambia and Zimbabwe large hydro average yearly capacity factor



Source: Climatescope 2019, BloombergNEF

3.2. Making room for renewables

A number of sub-Saharan African countries seem to have more than enough capacity to get by, their surpluses in generation capacity apparently obviating the need for new clean energy plants.

However, the situation is rarely so simple. Low plant availability and the expense of emergency power solutions keep the case for renewables compelling.

Long-term PPAs with fossil fuel IPPs have been critical to attracting private investment, but also lock governments into keeping capacity online for long periods. This can come at a significant cost. In the absence of effective planning, state-owned utilities can find themselves struggling to handle their contractual obligations and long-term contracts with IPPs can weaken the case for building renewables.

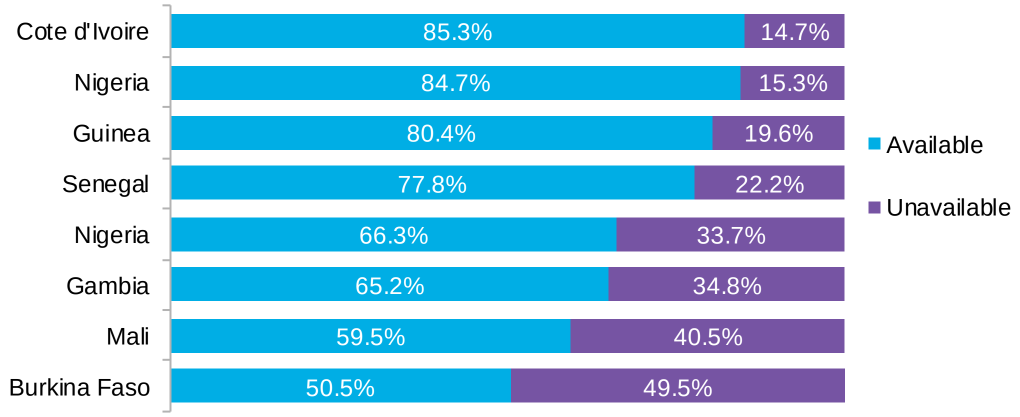
The year 2019 has seen several governments move toward renegotiating many such contracts in an attempt to reduce payments made to IPPs

Last year several governments tried to renegotiate contracts to reduce such obligations. But renegotiations are drawn-out and fraught, and risk damaging investor confidence.

Capacity oversupply

The gap between a country's installed generation capacity and that which is available is often large. Ageing plants are often ill-maintained. While such countries as Cote d'Ivoire can fire up most of their power fleet, some countries are considerably worse off. Burkina Faso, for instance, can just about call on half of its installed capacity online (Figure 30).

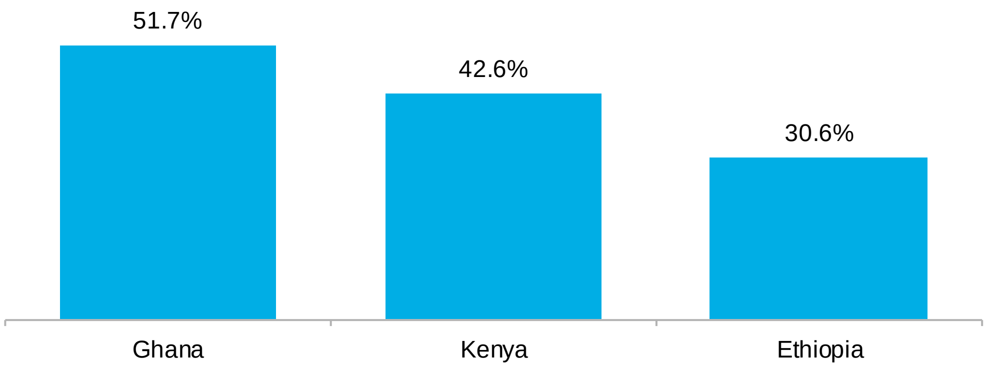
Figure 30: Available generation capacity of national power fleet in 2017, select countries



Source: BloombergNEF, WAPP

Most sub-Saharan African governments are struggling to meet demand. But a number sport an apparent over-abundance of generation capacity. Developers active in the region told BNEF that the view that certain markets are oversupplied has reduced some governments' willingness to back renewables projects. Policy makers in such countries as Kenya and Ghana have explicitly questioned the necessity of adding renewables to already-saturated power systems.

Figure 31: Generation capacity margins in 2018, select countries



Source: Climatescope 2019, BloombergNEF. Note: Capacity margin refers to the percentage by which total electricity generation capacity exceeds peak load. Graph refers to total installed capacity, not total available capacity.

Even when the expected disparity between available and installed capacity is taken into account, several countries sport sizeable capacity surpluses (Figure 31). However, their ability to meet supply is generally more tenuous than at first glance:

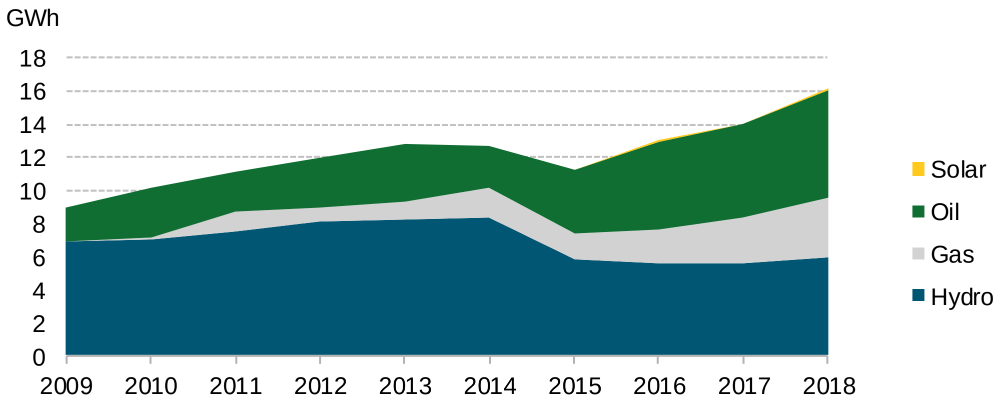
- In Ethiopia, hydro availability issues have led to power shortages. With large hydro accounting for 84% of capacity in 2018, a prolonged dry period led to a power deficit of nearly 500MW. The government imposed a rationing program in May 2019, suspending exports, curbing industrial demand, and implementing rolling power cuts to residential customers.
- Kenya Power, which has a monopoly on distribution and retail, announced that it would put the signing of new PPAs on hold in January 2019, citing excess capacity and financial issues. That froze 23 PPA applications representing at least 2.24GW of generation capacity.

  Despite a capacity surplus of over 50%, recent droughts have seen Kenya's 800MW of large hydro fall to half its usual availability. Moreover, some 190MW of fossil fuel plants are due to retire by 2023.

  For their part, variable renewables are making headway: the 310MW Lake Turkana wind farm commissioned in July 2019. But despite the high predictability of the site's wind resource, a lack of storage means that onshore wind cannot always be counted on to meet shortages.
- Ghana's oversupply stands out for several reasons. After supply struggled to meet electricity demand due to low hydro availability over 2014-15, the government contracted three emergency providers and signed 43 PPAs with IPPs. This led to pricy fossil fuels contributing to a far larger share of generation than had previously been the case (Figure 32).

  The result was a sizeable surplus of 1.8GW in 2018, with 2.3GW of power contracted on a take-or-pay basis. This has contributed to a freeze in future solar projects – oversupply is one of the main reasons for which a 2GW PV tender pipeline has been largely scrapped.

Figure 32: Electricity generation by technology in Ghana

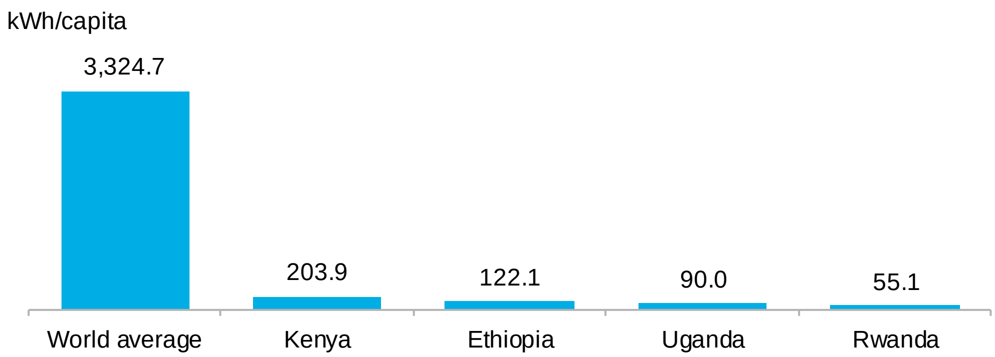


Source: Climatescope 2019, BloombergNEF

The perceived need for new generation assets is likely to increase as crossborder power trading takes off, allowing excess electricity to be sold abroad (see *Interconnection and power pools*). Moreover, electrification, rising living standards and industrialization will boost power demand across the region. Investment in transmission infrastructure will, however, have to increase for power fleets to be used to their full potential.

However constrained at present, future electricity demand growth will open up room for new additions in the mid- to long-term. The yearly consumption of the typical Kenyan, who uses considerably more electricity than the average African, is just over 6% of the global average (Figure 33).

Figure 33: Yearly electricity consumption



Source: Climatescope 2019, BloombergNEF

Payments to independent power producers

Take-or-pay PPAs involve offtakers paying independent power producers (IPPs) for the power produced regardless of whether it is consumed. Coupled with a perceived oversupply in generation capacity, long-term contracts linked to fossil fuel plants could dissuade governments from spending on new renewables. The situation is compounded by the absence of wholesale markets in which renewables might compete on price.

Few countries have put an end to the single-buyer model, whereby a national utility has a monopoly on power procurement. However, more are opening up their generation sector to private involvement. In the absence of an independent regulator in many markets, PPAs provide a form of regulation by contract. Cote d'Ivoire signed contracts with IPPs earlier than most, concluding the region's first PPA in 1994. The model has since spread across the continent.

IPPs accounting for a large share of domestic generation are, however, far from ubiquitous. Nine countries host the majority of independent generators active across the region (Figure 34). Although IPPs are the primary carriers of renewable energy projects, some 69% of contracted capacity is dedicated to fossil fuel plants (Figure 35).

Long-term commitments to buying power from fossil fuel plants could dissuade governments from spending on new renewables

Figure 34: IPP projects over 5MW in top IPP markets (excluding South Africa)

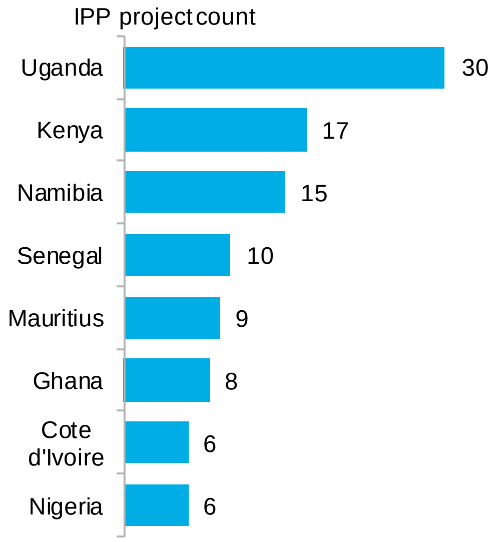
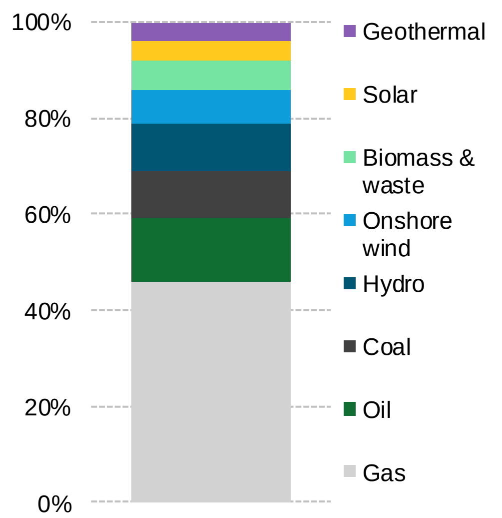


Figure 35: IPP-operated capacity (excluding South Africa) by technology

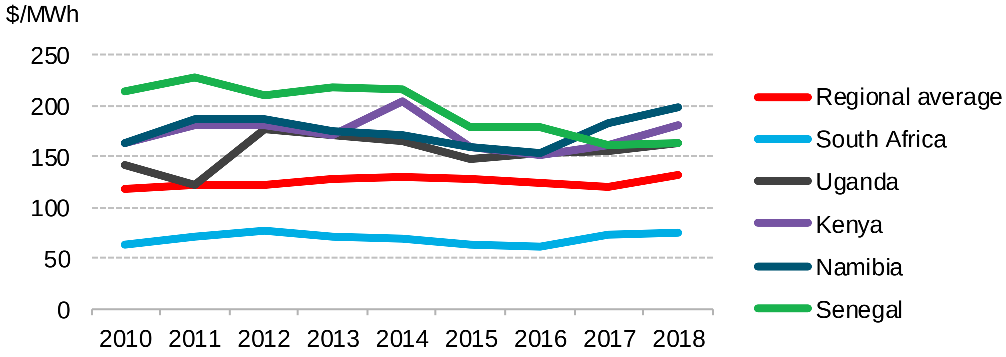


Source: BloombergNEF, Eberhard. Note: 2018 data.

Private investment has proven effective in driving the construction of new generation assets: it is no coincidence that those countries with the most IPPs host the most generation capacity. Most IPPs have benefited from take-or-pay contracts, which see generators remunerated regardless of whether the electricity they produce can be absorbed by the grid.

With the notable exception of South Africa, the presence of IPPs is correlated with higher retail prices, a trend reflective of the procurement costs that offtakers transfer to consumers (Figure 36). The prospect for future clean energy investment dims when governments struggle to pay IPPs. Either power market reform or contract renegotiations are required if renewables are to displace fossil fuel generation procured through long-term PPAs.

Figure 36: Average retail electricity prices, top five sub-Saharan African countries by number of IPPs



Source: BloombergNEF

Power purchase agreement renegotiations

Several governments have decided to reduce their obligations by renegotiating contracts signed with both fossil-fuel and renewables IPPs. Matters have come to a head in some of the region's largest markets: 2019 has seen Ghana and South Africa moving toward reviewing such contracts.

Renegotiations have targeted both thermal and renewables IPPs. And while they may free up additional budgetary headroom for governments to support new clean energy projects, this does not always translate to increased support for renewables. Depending on how they are carried out, such tariff revisions tend to deter prospective investors.

- **South Africa:** Just as state-owned utility Eskom ended a moratorium on signing new PPAs over 2015-18, the South African government decided in early 2019 that contracts concluded during the first rounds of the REIPPP auction framework be renegotiated to improve the utility's dire financial straits. The move affects 60-70 developers with 20-year PPAs amounting to 3.9GW, signed over the program's first three rounds in 2011-13 (Table 4).

  Successful bidders had received tariffs that were considerably higher than those achieved in the most recent procurement round, partly a result of higher technology and financing costs (Figure 37-38). A unilateral approach is, once more, unlikely due to the specter of legal challenges as seen in Spain. Following retroactive feed-in tariff cuts to Spanish renewables developers in 2013, the majority of ensuing arbitration cases were ruled in favor of developers.

Figure 37: Levelized REIPPP PV tariffs by delivery year

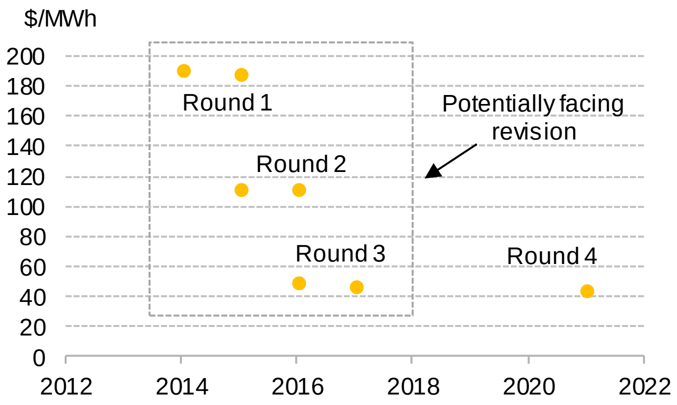
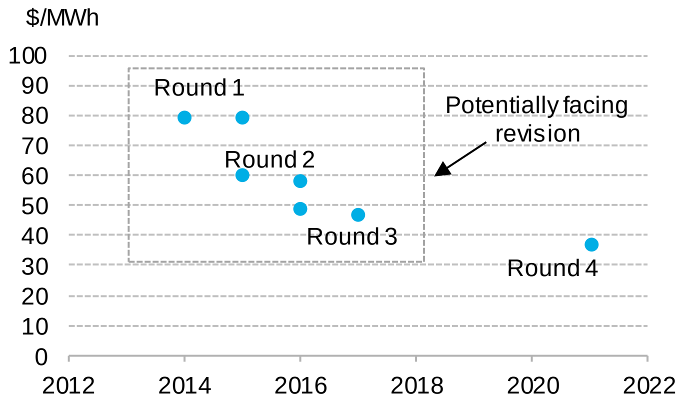


Figure 38: Levelized REIPPP onshore wind tariffs by delivery year



Source: BloombergNEF

Negotiations are now being framed as voluntary. IPPs were asked to draft proposals on how the process could proceed. A likely solution is for new PPA tariffs to be lowered while their terms are extended. South Africa has already renegotiated renewables PPAs in the past, but the latest round of contractual revisions will do little to encourage investors.

Table 4: Capacity allocation per REIPPP bid window (BW)

Technology	BW 1	BW 2	BW 3	BW 3.5	BW 4
Onshore wind	649	559	787		1,362
Solar PV	627	417	435		813
Solar thermal	150	50	200	200	
Small hydro		14			5
Landfill gas			18		
Biomass			17		25
Total	1,426	1,040	1,457	200	2,205

Source: National Energy Regulator of South Africa, BloombergNEF

- **Ghana:** Costly fossil fuel PPAs have saddled Ghana with crippling levels of debt (see *Making room for renewables*). Popular opposition to a 2016 tariff hike left the government with little choice but to focus on pushing down electricity production costs rather than keep raising tariffs. Finance minister Ken Ofori-Atta cautioned that the power sector's debt could reach $12.5 billion by 2023 – around a fifth of GDP.

  Talks to restructure PPAs began in August 2019. The government initially intended to adopt a uniform approach by reframing contracts as "take-and-pay", where the offtaker would only pay for the power consumed. The government appears to have backed down, and is now pushing for redrafting contracts to include a combination of take-or-pay and take-and-pay.

  But negotiations, carried out on a project-by-project basis, have dragged on beyond the three months initially predicted by the finance minister. They will likely continue well into 2020, and have been complicated by state utility Electricity Co. of Ghana running into mounting arrears on its IPP payments. Fossil-fuel plant operators have said that the government's desired changes would render projects uneconomical. Some have claimed that they would rather terminate PPAs than shift to take-and-pay.

The situation will need to be resolved for put- and call-option agreements (PCOAs) to be issued once more. A moratorium is currently in place on PCOAs, which ensure that the government compensates operators in the event of early contract termination. PPAs can be signed without a PCOA in Ghana, but financiers are likely to require them for renewables projects. But renewables rank low among the current administration's priorities: in an interview with BNEF in November 2019, Minister of Energy John Peter Amewu explained that the government views solar power as excessively expensive.

Only paying IPPs for power evacuated onto the grid would raise the barriers to investing in new power projects, with renewables hit especially hard

Official support for take-and-pay in Ghana is a shift in the public sector's strategy in dealing with IPPs. The concept has found traction elsewhere: Kenya Power said in September 2019 that the model could be used for future contracts, arguing that implementing such a framework would allow it to rein in its spending.

But only paying IPPs for power evacuated onto the grid would make investing in new power projects less attractive, with renewables hit especially hard due to their difficulty in accessing finance. While politically palatable, attempts to introduce take-and-pay are likely to be short-lived.

Such constraints mean that governments wanting to reduce the cost of existing PPAs are left with few good options. Renegotiations are drawn out, vulnerable to legal challenges, and tend to spook investors. But governments can soften the blow. The case-by-case negotiations seen in Ghana and South Africa are less likely to deter funding than blanket retroactive tariff cuts.

The outcome of negotiations will impact future investment – clean energy is unlikely to make much headway when existing PPAs are seen as a burden. Yet renegotiating PPAs is no cure-all. If struggling utilities' finances to be improved, governments will have to place a renewed emphasis on power market reform and energy planning.

Section 4. Interconnection and risk

Interconnection and power pools

Crossborder power cables allow for electricity to be traded between countries. Integrating national power systems yields a host of benefits, increasing security of electricity supply while expanding access to cheaper sources of generation. Crucially, being able to ferry electrons elsewhere makes integrating renewables easier, helping siphon off an abundance of wind or solar power that would otherwise flood the grid. Yet none of the region's markets currently host enough renewables for curtailment to be an issue.

However, a single project can have a large impact when national power systems are small. Coming online over 2018-20, two wind projects of 310MW and 158MW developed in Kenya and Senegal, respectively, amount to 14% and 11% of 2018 installed capacity. Few developed countries have witnessed as sudden an increase in their share of variable renewables. Further integrating regional power systems will be crucial if the likes of Kenya and Senegal are to keep adding clean capacity.

Bilateral PPAs typically provide the basis for crossborder power trading. Guaranteeing a set supply of electricity, such agreements come with the added benefit of providing predictable, fixed tariffs, often lasting over a decade. Wary of exposing themselves to fluctuating electricity prices, smaller countries might favor such agreements even when a competitive market exists.

Power trading is also carried out through river basin organizations (RBOs) such as the Organisation de Mise en Valeur du Fleuve Senegal (OMVS), in which Senegal, Mauritania, Mali and Guinea have a stake. The OMVS coordinates the management of the Senegal River, including overseeing the exchange of hydropower. Although the OMVS could provide a springboard for the West Africa Power Pool (WAPP), this could just as well be hindered by the fact that countries trading power over RBOs occurs far below market value.

Table 5: Sub-Saharan African power pools

Power pool	Regional economic community	Participating member states
Southern Africa Power Pool (SAPP)	Southern African Development Community (SADC)	Botswana, D.R.C., Lesotho, Mozambique, Namibia, South Africa, Swaziland, Zambia and Zimbabwe
Eastern Africa Power Pool (EAPP)	Common Market for Eastern and Southern Africa (COMESA)	Burundi, D.R.C., Egypt, Ethiopia, Kenya, Libya, Tanzania, Rwanda, Sudan and Uganda.
Western Africa Power Pool (WAPP)	Economic Community of West African States (ECOWAS)	Benin, Burkina Faso, Côte d'Ivoire, Gambia, Ghana, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone and Togo.

Source: BloombergNEF, ECPDM, SAPP. Note: The Central African Power Pool (CAPP) was created in 2003, but remains relatively undeveloped.

Market-based power trading has the potential to be driven by nascent regional power pools. Relying on pre-existing bilateral contracts before the establishment of day-ahead and intraday markets, power pools depend on interconnectors to create international electricity markets. The last quarter-decade has seen countries moving toward establishing power pools in southern, western and eastern Africa (Table 5). These generally operate as independent bodies under the aegis of their respective regional economic communities.

Power pools must contend with a number of challenges. Despite concerns regarding oversupply across the continent (see *Making room for renewables*), few countries host a generation surplus large enough for new transmission infrastructure to be economical. Political tensions can form another stumbling block: opposing the construction of a large hydro project on the Nile by Ethiopia, fellow EAPP member state Egypt temporarily withdrew from the organization in 2016.

The most advanced power pool is the oldest. The SAPP, formed in 1995, brings together 17 countries. Key backers include the AfDB, KfW and the World Bank. As well as spurring investment in the broader power sector and coordinating energy development, the pool promotes rural electrification and renewables. The organization also promotes regional power planning through a periodically updated master plan.

The SAPP's creation owes much to the subregion's complementary energy resources, linking hydro-abundant countries in the north with their thermal-rich southern neighbors. This eases hydro constraints while providing revenue for South Africa, the dominant exporter and producer of around three-quarters of the region's power. Yet the pool proved overly reliant on South Africa having a generation surplus. Increasingly slim reserve margins in the region's biggest power market led to a slump in regional trading since the mid-2000s (Figure 39).

Competitive trading has progressed despite the drop in traded volumes. A regional market platform allowing for short-term electricity trading was launched in 2001. This was superseded by a competitive regional day-ahead market in 2009. An intraday market came online in 2016. While most exchanges occur through bilateral contracts, competitive trading has accounted for an increasing share of total traded volumes over recent years, reaching 14% in 2017 (Figure 40).

Figure 39: SAPP yearly share of electricity traded through competitive markets and bilateral contracts

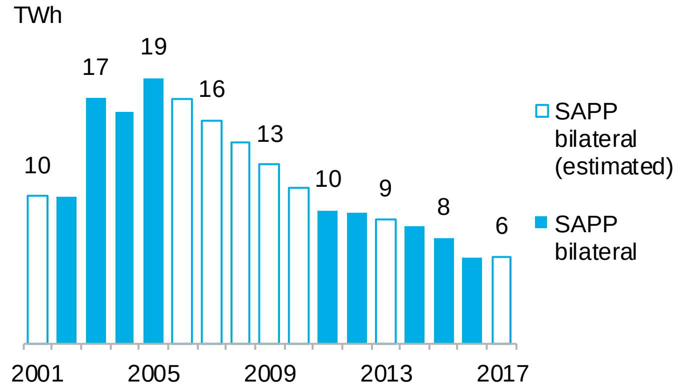
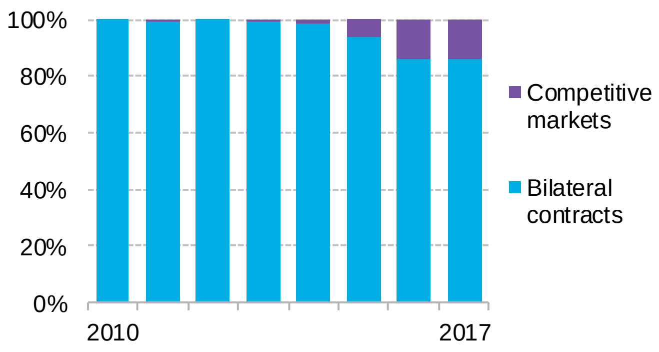


Figure 40: SAPP yearly electricity volumes traded through bilateral contracts



Source: Source: BloombergNEF. Wright, J.G., van Coller, J., 'System adequacy in the Southern African Power Pool', Journal of Energy in Southern Africa, 29, 37-50, 2018.

Much of the SAPP's success is owed to the regional powerhouse that is South Africa, but the crash in traded volumes highlights the danger of relying on a single market player. Similar concerns might arise concerning Ethiopia, whose 4.3GW of large hydro-heavy capacity in 2018 (with a 6GW hydro project in the pipeline) endows it with the largest power fleet in the EAPP. Ethiopia's hydro availability issues (see *Capacity oversupply*) will likely see regional trading progress in stops and starts.

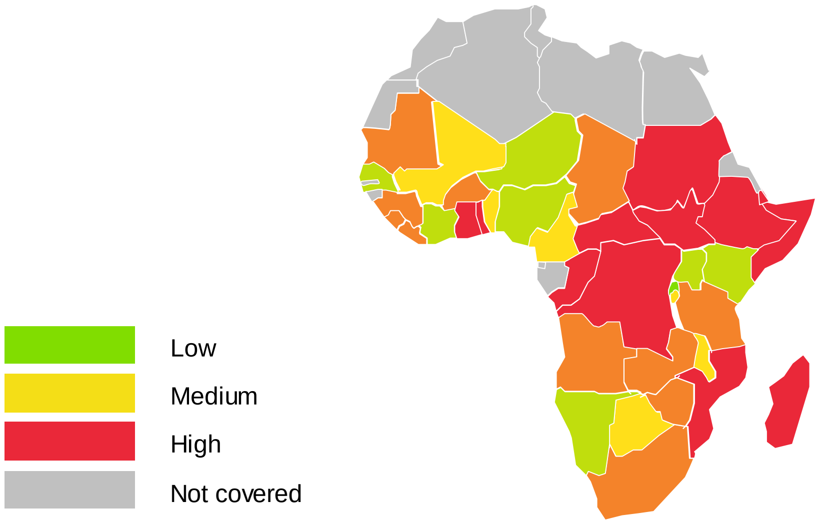
What little trading occurs through the WAPP and EAPP remains based on bilateral deals. Progress in developing interconnectors for the WAPP has proven particularly slow. Transmission infrastructure is costly, and lacks the political cachet of new power plants. Moreover, many governments will continue to focus on meeting growing domestic demand before they invest in crossborder lines. Widespread power deficits throughout sub-Saharan Africa will continue to hinder the development of regional electricity trading.

Offtaker risk

Renewables projects are exposed to a variety of risks. Developers must ready themselves for protracted land disputes, sudden policy changes and unstable currencies. But with an immediate impact on project revenues, offtaker risk – the risk of not getting paid on time or in full – is of central importance. Only eight of 36 of the countries surveyed by BNEF in 2019 were deemed to have the lowest level of offtaker risk (Figure 41).

Uganda was the sole sub-Saharan African where power sector utilities collected enough revenue to cover their operating expenses and capital depreciation

Figure 41: Risk of delayed or non-payment by offtaker

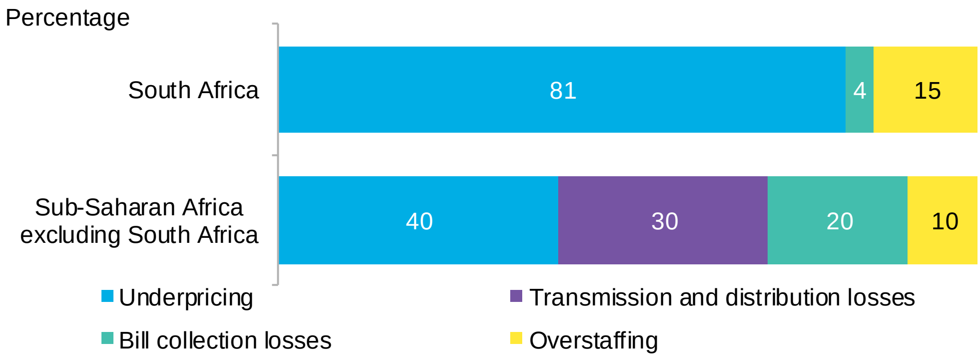


Source: Climatescope 2019, BloombergNEF

Such high levels of risk arise from the fact that most of the region's utilities are struggling financially. A 2016 World Bank report found that, when island nations were excluded, Uganda was the sole sub-Saharan African where power sector utilities collected enough revenue to cover their operating expenses and capital depreciation. Poor financials leave them vulnerable to such unexpected shocks as drought-induced power shortages (see *Large hydro*).

The factors contributing to power companies' low bankability are manifold. Subsidized retail tariffs are the largest hidden cost to the region's utilities (Figure 42) and are rarely cost-reflective. Ageing transmission and distribution (T&D) infrastructure leads to substantial power losses. Countries with high T&D losses tend to correlate with those where bill collection is also an issue.

Figure 42: Breakdown of hidden costs



Source: BloombergNEF, World Bank

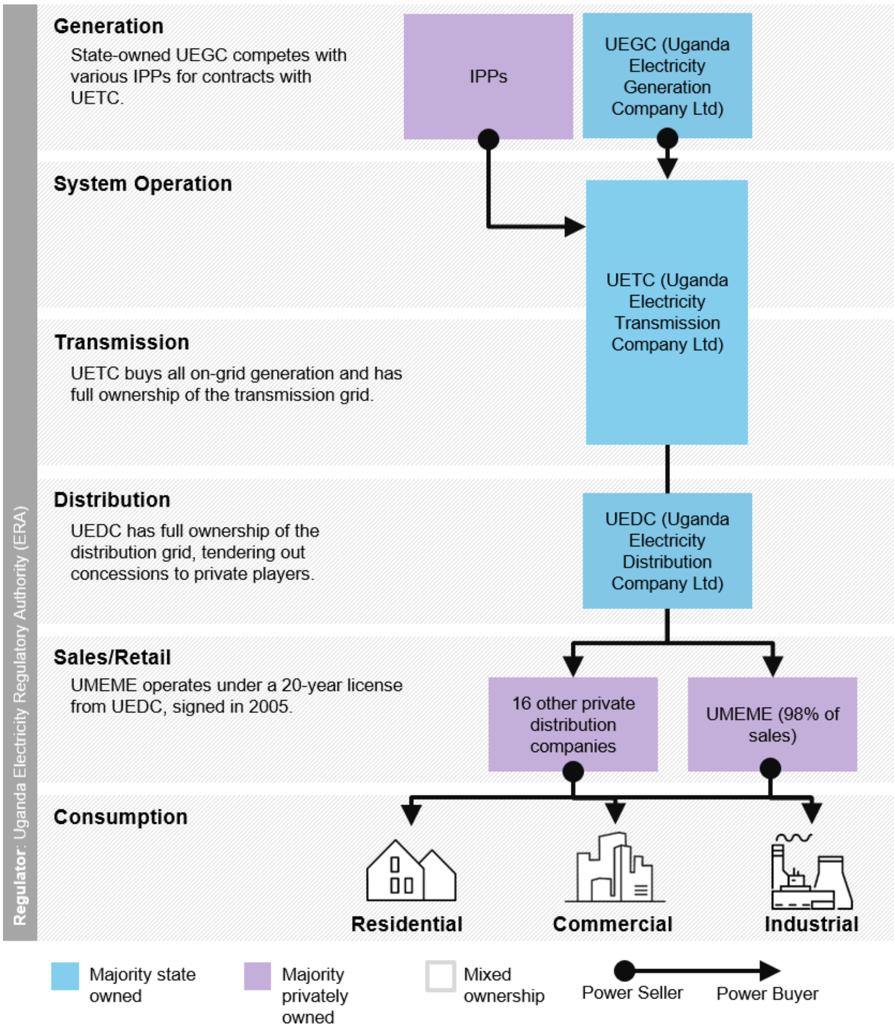
Attempts to tackle such issues head-on have met mixed results. Average retail prices have been increasing across the region, but charging customers more is not easy. Attempts to raise residential tariffs, which account for a far larger share of utility revenue in sub-Saharan Africa than the global average, are politically sensitive. Even when price hikes spare poorer customers, the list of the region's governments that have backtracked in the face of the resultant unrest is long.

A prime example is Cote d'Ivoire, where a 30-40% tariff increase in the summer of 2016 was met with widespread demonstrations. The government mandated that tariffs be lowered again, compensating affected users. Despite prices pressure from international donors to raise tariffs, Cote d'Ivoire has not attempted another increase since. But other reforms have ensured that payments are made regardless of the offtaker's financial health. A "cash waterfall" system set up in 1998 has forced the state utility to prioritize payments to IPPs, shielding private investors even during bouts of political turmoil.

Priorities vary: some governments are more focused on reducing non-cost-reflective retail rates. For instance, the Senegalese government hopes that a shift to cost-effective renewables and gas will allow public utility Senelec to bring prices down. While Senelec has significantly improved its financial situation through such measures as rolling out pre-paid metering, it remains 377 million euros in debt. It has paid little heed to the regulator's call to raise rates by 39% in 2019. But this does not necessarily translate to a high level of offtaker risk: renewables IPPs interviewed said that Senelec can be counted on to make payments on time.

Power market reform is often cited as a solution to indebted offtakers. Breaking up vertically integrated utilities facilitates the efficient management of generation, transmission and distribution. Uganda was the first African country to completely unbundle its state utility, starting the process in the late 1990s and succeeding in attracting a high number of IPPs. The reforms were politically controversial, and most of the unbundled utilities remain state-owned (Figure 43). However, the Ugandan energy sector's transition has resulted in increased collection rates and lower transmission losses.

Figure 43: Uganda power market structure



Source: BloombergNEF

Having a bankable offtaker has made it easier to attract renewables investment, helping Uganda come fourth in the region in BNEF's Climatescope 2019 ranking. Unbundling also allows IPPs to sign contracts with the Uganda Electricity Transmission Co. (UETC) – the only offtaker – directly. This reduces the chance of conflicts of interest arising with state-owned generators, as Meyer et al. note. Moreover, UETC's ability to act as a credible counterparty has facilitated the establishment of renewables procurement schemes. GET FiT Uganda is generally recognized to have been a successful, pioneering foray into clean energy auctions.

A number of countries are moving toward unbundling. The president of South Africa, Cyril Ramaphosa, announced in February 2019 that ailing state utility Eskom would be split up. The government has outlined that it hopes the process will be completed by 2022, hinting that it might cleave a new generation subsidiary into two competing entities. These plans could, however, be watered down by resistance from trade unions, which fear the breakup will lead to widespread layoffs. Either way, transmission is considered the utility's most profitable segment, and is as such likely to be split off earlier.

Additional measures are required to handle Eskom's 440 billion-rand ($29 billion) debt. Available solutions range from selling coal power plants to clamping down on municipalities that are behind on payments. Alternatively, part of the company's obligations could be shifted onto the state's balance sheet, but might also be put into a special purpose vehicle to be refinanced.

Since the IMF's structural development programs in the 1990s, funders have pressed the region's countries to break up their power sector. In 2015, the U.S. government's Millenium Challenge Corp. made a $469 million support package to Ghana's state utility contingent on it being unbundled. But the limits of liberalization have been laid bare in Nigeria, where the fate of the Power Holding Co. of Nigeria (PHCN) in 2011 serves as a cautionary tale. Six generation companies (gencos), eleven distribution companies (discos) and a TSO were all spun out of PHCN and sold to private investors.

Yet as far as power market reform had progressed, a number of factors hampered market reform. Private actors underestimated the running costs of discos and gencos have complained that the offtaker, Nigeria Bulk Electricity Trading Plc, does not meet its payment obligations.

To add to such issues, 14 utility-scale solar projects adding up to over 1GW (Table 6) have been frozen by negotiations – the government is pressuring the developers to reduce tariffs agreed in July 2016. Along with the AfDB and African Finance Corp., the UN's Green Climate Fund said in February 2019 that it would provide support to help 400MW of the stalled pipeline reach financial close, but little progress has materialized to date.

Table 6: Nigerian solar projects awaiting development

Company	Capacity	PCOA signed?
Afrinergia Power Ltd.	50MW	April 2017 ($0.075/kWh)
CT Cosmos Ltd.	70MW	April 2017 ($0.075/kWh)
Pan Africa Solar	75MW	No
Nigeria Solar Capital Partners	100MW	No
Motir Desable Ltd.	100MW	No
Nova Scotia Power Dev Ltd.	80MW	No
Anjeed Innova Group	100MW	No
Nova Solar 5 Farm Ltd.	100MW	No
KvK Power Ltd.	100MW	No
Middle Band Solar One Ltd.	100MW	No
LR Aaron Power Ltd.	100MW	No
En Africa	50MW	No
Quaint Abiba Power Ltd.	50MW	No
Oriental Renewable Solutions	50MW	No

Source: Energy for Growth, BloombergNEF. Note: The put call option agreement (PCOA) guarantees payment in the event that NBET defaults on its payment obligations.

Managing project risk

Because bankable sub-Saharan African utilities are few and far between, special measures are required to address risk, pushing up project financing costs across emerging markets (Figure 44-45). Renewables developers have a range of options at their disposal. Currency risk must also be addressed – more often than not, contracts for utility-scale renewables plants will be signed in hard currency. But different hedging instruments are employed in the rare event that tariffs are denominated in local currency.

Figure 44: The effect of financing costs on levelized costs of electricity, utility-scale PV, 2019

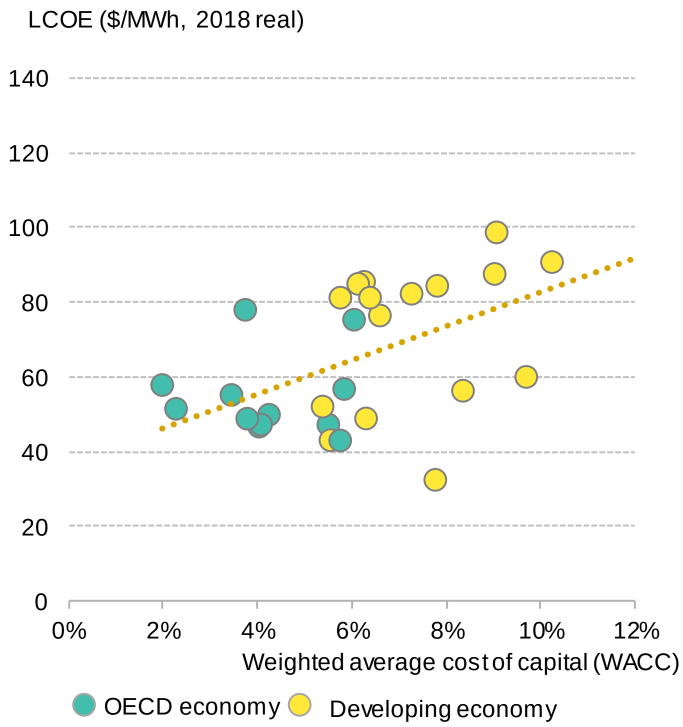


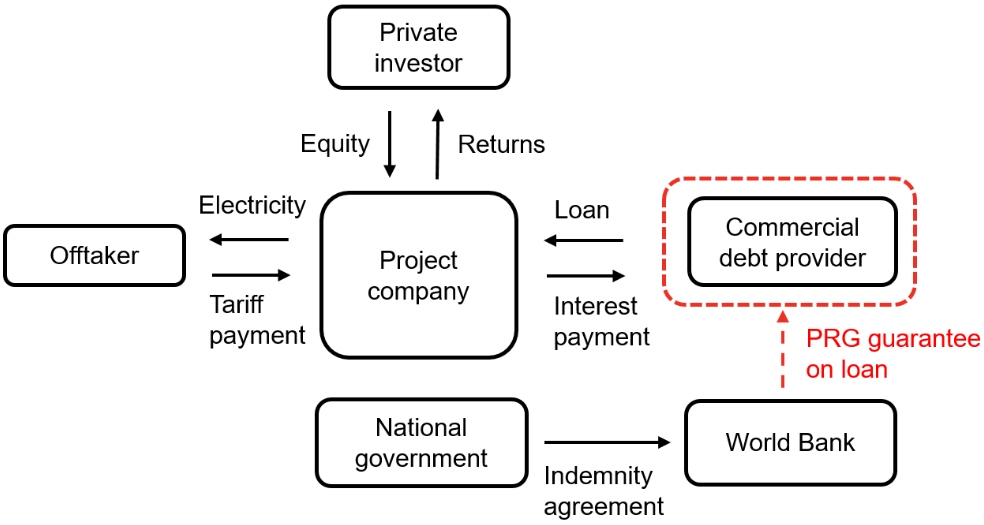
Figure 45: The effect of financing cost on levelized costs of electricity, onshore wind, 2019

Source: BloombergNEF

Partial risk guarantees: Partial risk guarantees (PRGs) are becoming increasingly available for utility-scale renewables – World Bank and AfDB and the Overseas Private Investment Corp. (OPIC) are their main issuers. PRGs protect private lenders against the risk of state-owned offtakers not honoring their contractual obligations – they are not issued when the counterparty is a private utility (Figure 46). They usually cover the outstanding principal and accrued interest of a specific debt tranche in full, with payments made in the event that the service default is linked to the specified risks.

October 2019 saw the AfDB announce that it would provide such a guarantee for Chad's first utility-scale solar-plus-storage projects. The PDG will be issued alongside a $19.7 million loan for the first 32MW phase of the 60MW Djermaya solar project, developed under a 25-year PPA signed with the state utility. But while attractive, PRGs come at a cost. GET FiT Uganda's renewables procurement scheme offered PRGs to developers. While the provision of guarantees proved useful for attracting investors, most developers preferred to do without, avoiding the extra expense.

Figure 46: Example of partial risk guarantee deployment



Source: BloombergNEF

Some developers have shown a willingness to proceed with projects backed by letters of comfort, displaying the host government's soft support

Sovereign guarantees: Such guarantees are offered by governments. They cover payment defaults by state-owned offtakers and are similar to PRGs. They differ in that they cover the revenue lost by the project company, rather than interest payments to the lender. Sovereign guarantees are complementary with PRGs for a project's equity tranche. Deployed together, the two guarantees confer full coverage of offtaker risk. But although they are highly prized by developers and investors alike, governments are often reluctant to sign such guarantees.

Some developers have shown a willingness to proceed with projects backed by letters of comfort, displaying the host government's soft support. Letters of comfort are not binding – governments can issue them without taking on any legal obligations. However, such assurances have been sufficient for financing renewables projects in countries with access to capital markets and low levels of offtaker risk, such as Kenya.

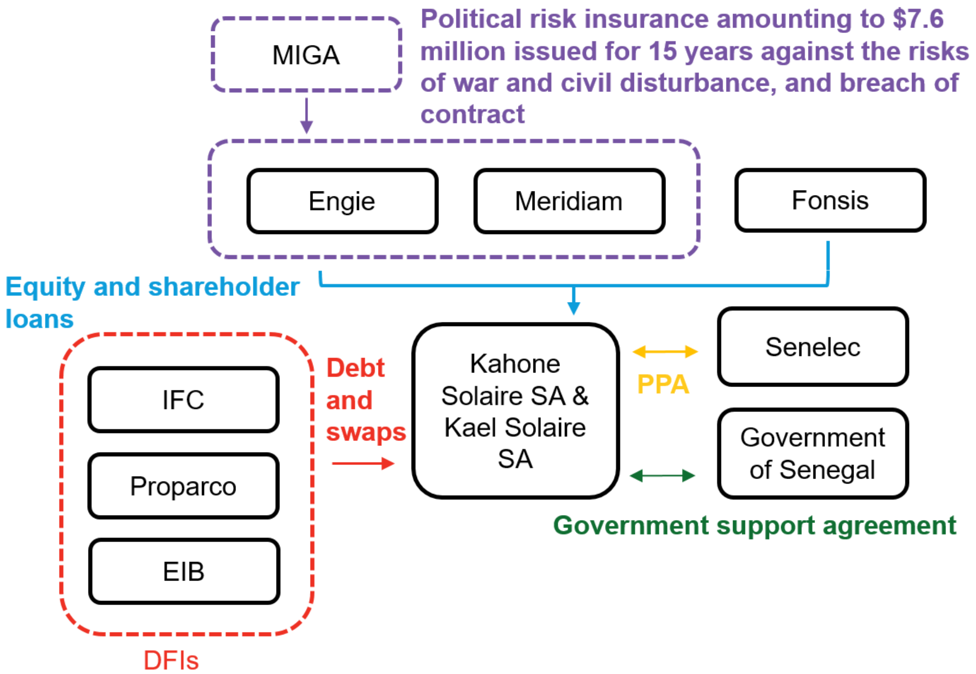
Credit guarantees: A range of actors provide tools that mitigate risk for debt investors. The World Bank offers partial credit guarantees. They cover part of the debt services to commercial lenders or bond holders, but must be backed by a sovereign counter-guarantee. More specialized players have also emerged: Guarantco is a privately-managed entity funded by four European governments and Australia. It typically sets up partial credit guarantees to infrastructure projects for local currency loans and bonds. This makes it possible to raise debt finance from domestic commercial banks, few of which are active in financing renewables.

Export credit guarantees allow governments to promote their domestic equipment manufacturers in emerging markets. The Danish Export Credit Agency notably backed local commercial bank debt provided to Kenya's 310MW Lake Turkana wind farm, which used 0.85MW turbines made by Vestas. In view of promoting domestic technology providers, developed countries have shown a marked willingness to offer large volumes of low-cost concessional financing.

Political risk insurance: Power infrastructure projects in sub-Saharan Africa have access to the World Bank's Multilateral Investment Guarantee Agency (MIGA), which provides an assortment of political risk insurance products. Complete MIGA coverage protects against political, currency and offtaker risk.

Political risk insurance has long involved deal sizes too large to be economical for renewables, which tend to be smaller than fossil fuel plants. But this is changing as larger clean energy projects see the light of day. Although MIGA is the largest provider of such products for renewables, it is far from alone – the EIB, AfDB, OPIC and the African Trade Insurance Agency all offer similar instruments. In July 2019, MIGA announced the coverage of two PV projects in Senegal of a total 60MW, both of which awarded through Scaling Solar (Figure 47).

Figure 47: Political risk insurance provision for two Senegalese PV projects



Source: MIGA, BloombergNEF. Note: Financial close for both projects was reached in July 2019.

Mitigating currency risk: Sub-Saharan Africa's currencies are more volatile than their OECD counterparts. Developers often seek funding in hard currency as a result – most PPAs for large-scale renewables are signed in dollars or euros, shifting currency risk to the offtaker. Some markets are beginning to experiment with local currency PPAs, but most rely on some form of sovereign guarantee and fixed exchange rates.

In the unlikely event that payments are denominated in local currency, developers can fall back on hedging instruments. Long-term currency swaps allow the buyer to transfer the risk of local currency depreciation. However, while a number of funds are providing such instruments, interviews with developers active in the region indicate that they are often perceived as too pricy.

Some countries see a developer's revenue tied to a hard currency but paid out in local currency. This is an issue with countries with local liquidity, such as Ethiopia and Nigeria. Nigeria's reserves fluctuate due to its dependence on revenue from exporting natural resources (Figure 48). And while reserves have remained at stable, albeit low, levels, access to forex in Ethiopia has worsened in recent years. In such cases, developers generally seek convertibility guarantees from the government before committing to a project. As mentioned above, such risks can be covered by certain political risk insurance schemes.

Section 5. Offgrid power

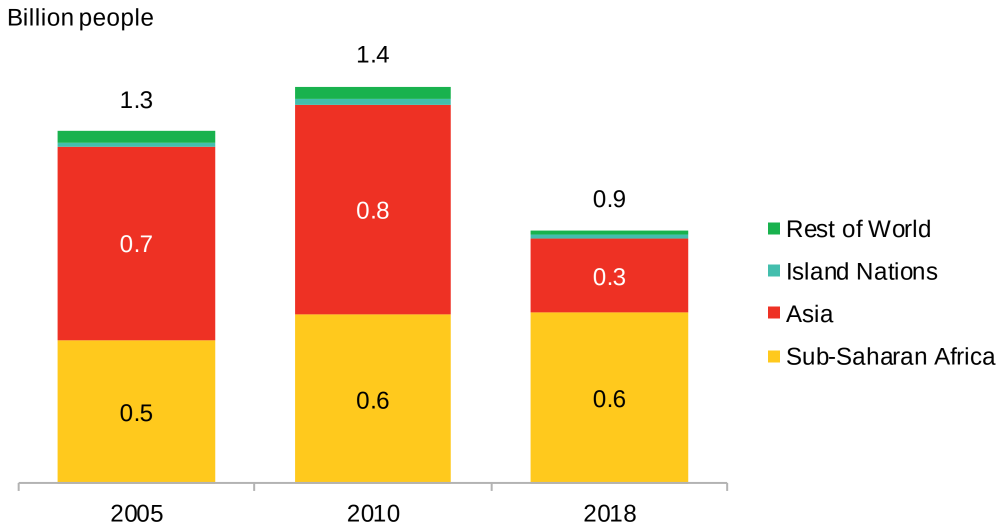
Of the main solutions for electrifying the region's population, grid expansion will continue to receive the greatest share of investment. Yet new policy incentives are increasingly supporting developers deploying renewables-hybrid microgrids. And while solar home systems will attract less in the way of overall funding, intensifying competition will reshape the sector over the years to come.

5.1. Electricity access

Viewed as a region, levels of electricity access in sub-Saharan Africa are the world's lowest. Population growth has meant the number of Africans living without power has barely budged over the last decade, stubbornly remaining at around 600 million (Figure 48).

The number of Africans living without power has barely budged over the last decade, stubbornly remaining at around 600 million

Figure 48: Global population without access to electricity

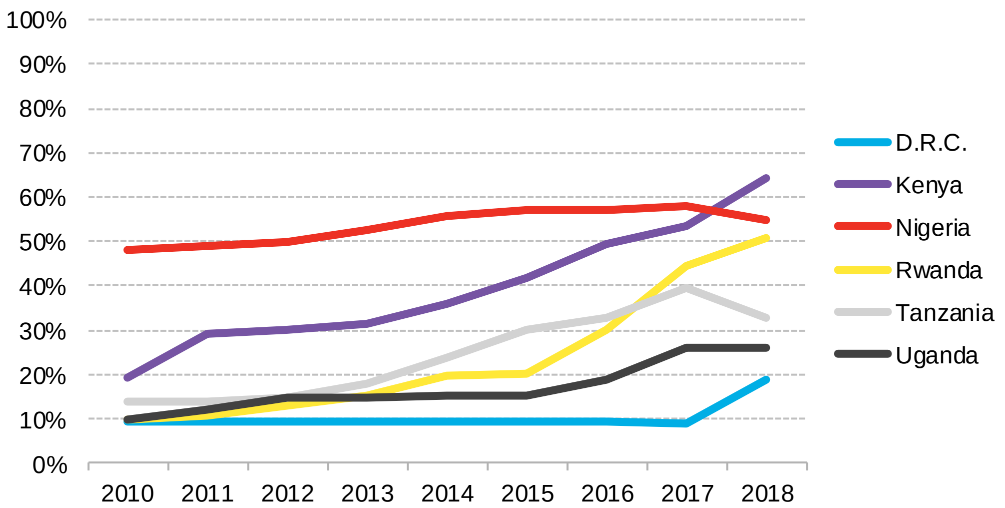


Source: Climatescope 2019, World Bank, BloombergNEF

Electricity access rates differ substantially across the continent. Blistering progress has been achieved by countries such as Rwanda (population 12.3 million) while giants like Nigeria (population 195.9 million) have remained stagnant (Figure 49).

Many of the region's governments have pledged to achieve universal access at some point before 2030. Most targets have been set in line with the seventh of the Sustainable Development Goals adopted by the UN in 2015, and have been enacted by a majority of the region's countries. Climatescope 2019 recorded only 10 as having set no such goal.

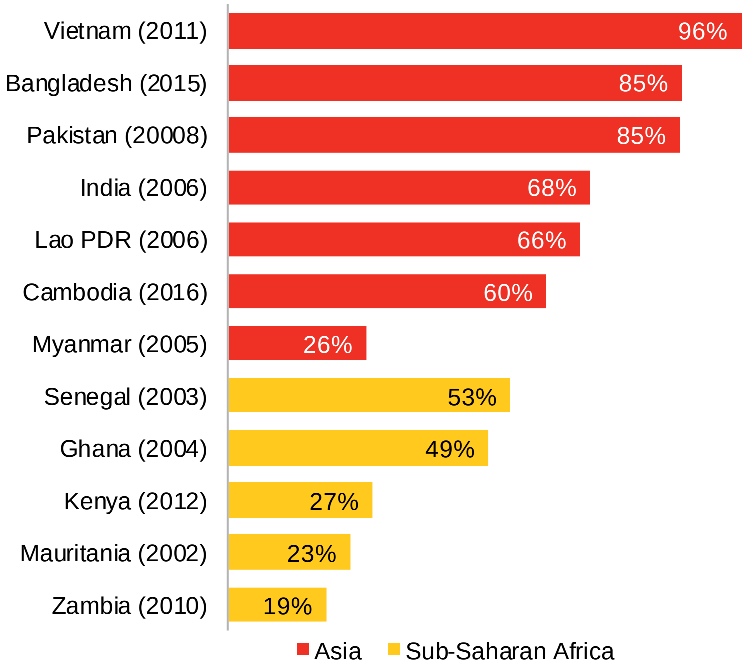
Figure 49: Electricity access rates, select sub-Saharan African countries



Source: Climatescope 2019, BloombergNEF

A series of pledges backing electrification matters, as history has shown that income is not the primary driver of energy access. A look at national electrification rates countries reach as they achieve $1,000 GDP per capita shows that the government's commitment to electrification matters most (Figure 50). The progress achieved in Rwanda and Kenya shows that, when backed by DFI-funding, determined policies can achieve rapid improvement.

Figure 50: Electrification rates when reaching $1,000 GDP per capita



Source: BloombergNEF

Populations without access to power can be connected by extending the main grid, building community-level microgrids or through household-level systems such as solar home systems. Different offgrid options compete with the grid on the cost of electricity, deployment speed and profitability (Table 7).

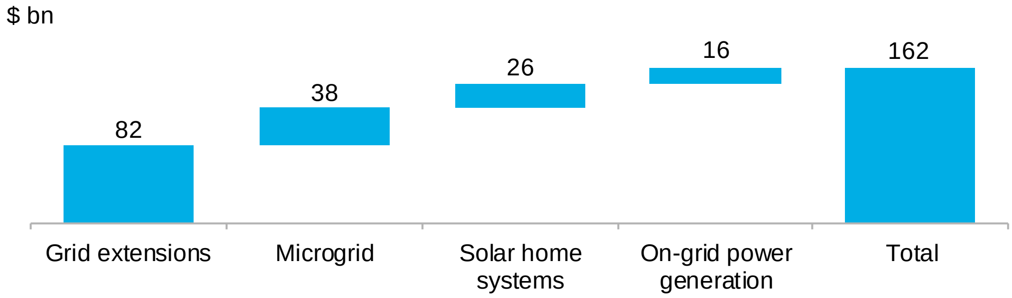
Table 7: The main approaches to provide electricity access

Option		Advantages	Risks	Typical size
	**Extending the main grid**	• Cheapest power generation cost • Good for high amounts of power demand	• High initial cost • Lengthy process to build • Cost rises with remoteness	NA
	**Microgrids**	• Local aggregation of demand • Powers AC or DC appliances and equipment	• Risk of stranded assets if the grid is extended • Low power demand makes it difficult to recover costs	~ 10 – 200kW
	**Solar home systems***	• Deployed through retail channels • Targeting based on individual credit risk	• Very costly per unit of energy • Limited range of appliances that can be powered	10 – 300W
	**Solar lantern**	• Can cost as little as $5	• Provides only lighting and possibly phone charging • Excluded from our analysis as it is considered insufficient for even basic electricity access	<10W

*Source: BloombergNEF. Photo source: Bloomberg, d.light. Note: *In this report, we define these as plug-and-play solar home systems that do not require an individual selection of components.*

BNEF predicts that extending national grids will receive over half of all global investment in electricity access over 2018-30. As far as distributed electrification options are concerned, microgrids will receive the next largest share, followed by solar homes systems (Figure 51). This trend is expected to be replicated in sub-Saharan Africa.

Figure 51: Projected electricity access investments 2018-30, base scenario



Source: BloombergNEF

Governments vary in their approach. Most sub-Saharan African states have established a rural electrification agency, which typically oversees electrification programs. Such bodies may also control rural electrification funds. But key decisions concerning electrification initiatives may ultimately lie with the regulator or the ministries of energy and finance, muddying the waters around to whom developers should turn.

In addition to such agencies, many countries have drawn up electrification strategies detailing how they hope to bring power to their citizens. With a national electrification rate of 38%, Togo published its electrification roadmap in late 2018, aligning it with its universal access target by 2030.

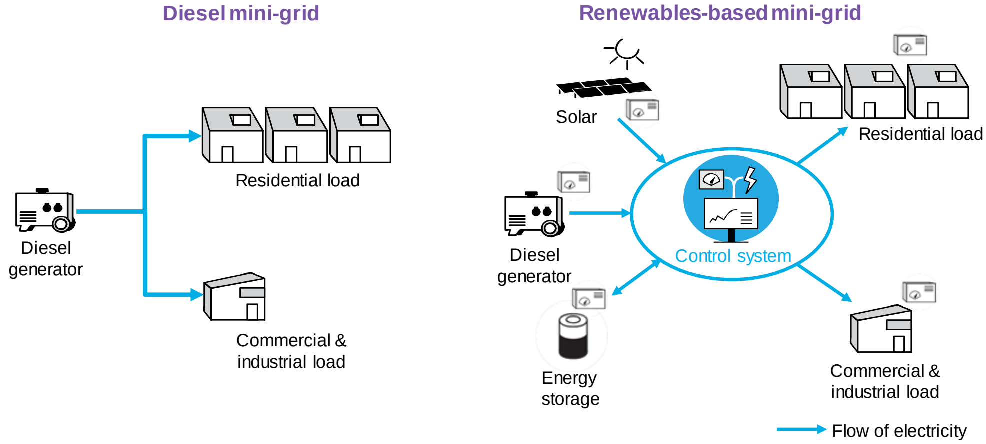
Basing its conclusions on electrification models and case studies, Togo's government provided clear investment signals by detailing the roles to be played by grid connections, solar home systems and microgrids in its document. Lowest-cost technology choices are shown for over 3,000 communities across the length of the country.

5.2. Hybrid microgrids

A microgrid is a group of interconnected distributed energy resources and loads within a clearly defined boundary. Its main feature is the ability to operate independently, allowing them to be set up in remote conditions that the main grid cannot reach. In the past, microgrids have typically been connected to a single generator or small hydro plant, providing power to customers over a distribution network (Figure 52).

Sinking PV and battery storage costs have made hybrid microgrids combining various generation technologies viable. Most microgrids in sub-Saharan Africa are isolated, but these can also be connected to the main grid, either through grid extensions or from the outset by customers wanting more reliable, cheaper power.

Figure 52: Microgrid system architectures (off-grid)



Source: BloombergNEF

Assuming no additional policy, BNEF sees grid extensions receiving the highest share of investment in electrification. This is a result of both familiarity to policymakers and the grid's economic advantage over other solutions. But the picture changes if it is assumed that countries will work toward achieving universal energy access.

While the UN's definition is loose, BNEF interpreted universal access as a household consumption of at least 300kWh per year or a 200W solar home system. If such a goal were met, microgrids would electrify nearly as many people as the grid and receive the largest chunk of funding (Figure 53-54).

Figure 53: Technology use 2018-30 in universal access scenario in sub-Saharan Africa

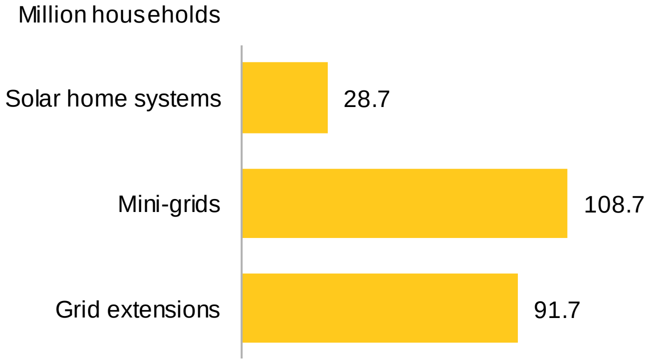
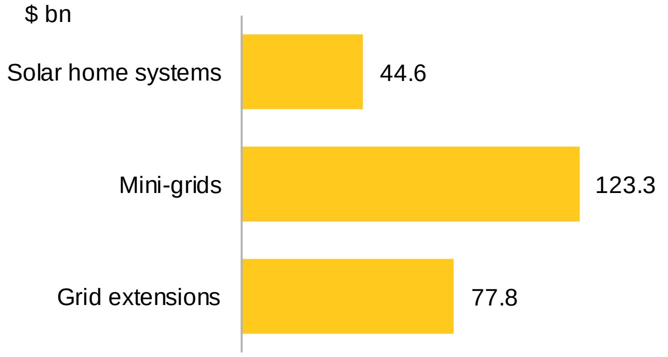


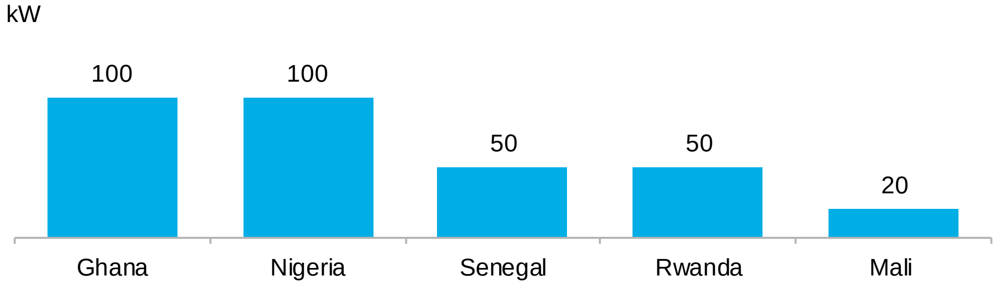
Figure 54: Capital expenditure 2018-30 under the universal access scenario in sub-Saharan Africa



Source: BloombergNEF

Many countries require some form of license to set up a distribution system and sell power to customers. Certain frameworks, such as Tanzania's, award licenses for multiple sites. A growing number of countries exclude the smallest projects from requiring such certification, although the obligation to register the microgrid often remains. The relevant capacity limit can vary considerably, ranging from 20kW to 100MW in sub-Saharan Africa alone (Figure 55).

Figure 55: Microgrid capacity thresholds for license exemptions, select markets



Source: BloombergNEF. Note: Projects under 2MW Uganda can be exempted, but require a certificate of exemption, the acquisition of which has been reported as taking up to a year. Tanzania's legislation sets a 100kW threshold, but interviews with developers indicate that it is not respected in practice.

Hybrid microgrids remain reliant on subsidies. One type of support is an upfront capital cost subsidy, but recent years have seen the promotion of results-based financing (RBF), which involves paying a sum upon completion of certain criteria. RBF schemes offer greater oversight over when payments are disbursed, but are more complex. Launched in June 2019, a performance-based grant program for hybrid microgrids is being implemented in Nigeria. On top of a base subsidy payment, developers receive a results-based grant of $350 per connection.

Given the risk of asset expropriation, operators must also have visibility on the intended procedure upon the arrival of the main grid. Tanzania notably created rules allowing microgrid operators to keep selling to customers, imposing cost-reflective tariffs regardless of grid arrival. Other frameworks allow developers to sell power directly to the grid.

5.3. Solar home systems

BNEF expects solar home systems (SHS) will see the smallest share of global investment over the decades to come, compared with grid extensions and microgrids (Figure 51). But SHS will remain competitive in many cases, as they can be deployed faster and more cheaply while allowing customers to be targeted individually.

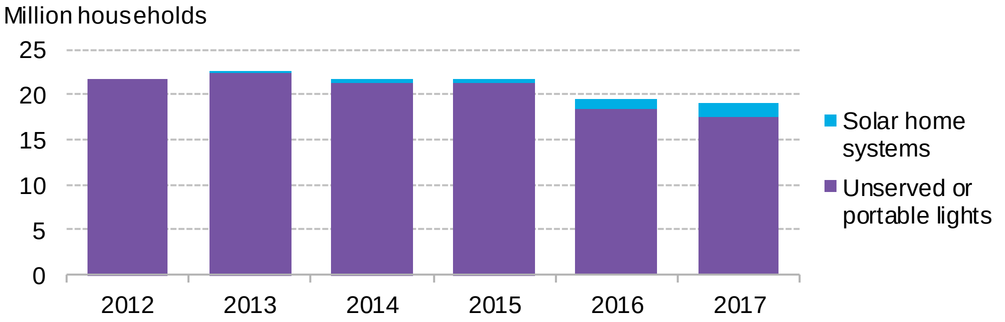
SHS cost declines are expected over the coming decade as they are bundled with super-efficient DC appliances

Such household systems are often less efficient than other electrification technologies in terms of cost per kilowatt-hour, which can exceed $1.50/kWh. Cost declines are expected over the coming decade as they are bundled with super-efficient DC appliances, however. SHS can be the least-cost technology where power demand is low and households dispersed.

Most market activity in sub-Saharan Africa is in eastern Africa, although many of the biggest market entrants have made inroads across the rest of the continent. Eastern Africa shows that SHS can reach a large portion of the population within a short timeframe (Figure 56). Expansion is growing at such a clip that, should the current trajectory be followed, market penetration rates could reach 70% by 2030.

Other parts of the continent will likely see similar uptake. Over recent years, a number of major SHS firms have established a presence in western Africa. It is worth noting that the majority of deployed systems will provide just enough power for basic necessities, falling short of that required for such energy-intensive processes as refrigeration and cooling.

Figure 56: Eastern Africa's population not connected to the grid



Source: BloombergNEF

Competition among SHS providers is heating up. Eastern African markets like Kenya, Tanzania and Rwanda have become crowded, with such top plays as d.light, BBOXX and M-KOPA jostling for space. Mobisol, one of the sector's early pioneers, filed for bankruptcy in April 2019. It had notably relied on financing from impact investment and development financing entities, while its competitors secured funding from a wider range of sources.

Engie announced its acquisition of Mobisol on September 3, 2019. The takeover complements Engie's existing activities. Engie will now be retailing SHS in Africa's largest markets: Kenya, Tanzania and Rwanda. The estimated total off-grid market revenue in countries where Mobisol operates is around $167 million in 2H 2018.

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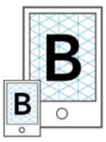

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