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Decarbonising Africa's grid electricity generation

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Executive summary

The world faces a climate emergency. Global greenhouse gas emissions are falling nowhere near fast enough to avoid massive harm from global warming. The emissions from power plants alone, already operating or commissioned worldwide, have exhausted the carbon budget compatible with keeping warming to 1.5 degrees.

Africa faces a poverty emergency. The proportion of Africans living in extreme poverty is falling but population growth means the absolute number is still rising, and most projections foresee that trend continuing to 2030. And eliminating the most extreme poverty (as measured by purchasing power parity (PPP) of $1.90 per day) is an unacceptably low bar for African development aspirations.

The rapid expansion of reliable and affordable electricity for industry and commerce is essential to the continent's development. A decent standard of living also requires a far higher level of domestic power consumption than most Africans can access today. Average annual power consumption per person in sub-Saharan Africa (excluding South Africa) is around 500 kilowatt hour (kWh), compared to about 13,000kWh in the United States (US) and 6,500kWh in Europe.

Sub-Saharan Africa, home to more than one billion people, is responsible for just 0.6 per cent of cumulative global carbon dioxide emissions, but economic and population growth imply that by 2050, African emissions will not remain immaterial. Almost every African country has signed the 2015 Paris Agreement on climate change, and joined the effort to achieve net zero carbon emissions by mid-century. But the Paris Agreement also recognises that the imperative of economic development implies that emissions from less-developed countries will rise over the medium-term, before falling.

This review examines the technological and cost considerations that will constrain the pace of decarbonisation in centralised electricity grids, alongside Africa's crucial energy access and economic development goals. There are also tremendous opportunities for decentralised approaches, such as solar mini grids, to add impetus to the decarbonisation of the overall electricity sector, but our focus in this report is on the centralised grids that are an indispensable element of electricity provision. Our intention is to provide evidence about the realities of African power networks to inform the discussion of how the continent can make the transition to net zero, together with rapidly expanding the supply of reliable and affordable electricity.

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The extraordinary decline in the costs of utility-scale renewable energy sources such as solar photovoltaic (PV) and wind, and energy storage technologies such as batteries, has kindled hopes that African countries can move straight to 100 per cent renewable power. The rapid adoption of renewables will allow Africa to avoid the path of heavy reliance on fossil fuels that others have trodden, but the reality today is that many African countries cannot yet get everything they need from renewables alone. As electricity systems approach 100 per cent fossil-free, Sepulveda, et al., (2018) argue that batteries and demand management cannot substitute for what they call 'firm' clean resources (meaning generation that can be relied upon to produce power as planned), such as gas with carbon capture or reservoir hydro. Moreover, without firm resources, energy storage costs rise increasingly rapidly the closer one gets to designing a reliable grid with zero emissions. As storage technologies advance, the costs of the investments required to facilitate very high variable renewable energy (VRE) penetration will fall, but those African countries without clean firm resources (hydro, biomass and geothermal) cannot wait.

According to 2020 projections by the International Energy Agency (IEA) the average 'levelised cost of energy' (LCOE) for utility scale solar PV and onshore wind is now often below gas (average LCOEs being $56/megawatt hour (MWh), $50/MWh and $71/MWh, respectively,) and records fall every year for lower electricity pricing from solar and wind projects.[1] These low LCOE prices do not account for the additional system costs that are needed to maintain the supply of reliable power year-round. Integrating high shares of solar and wind VRE requires back-up power for when output is low. Low prices per kWh for wind and solar under power purchase agreements (PPAs) also typically requires the 'offtaker' to pay for the output generated even when it is not needed, which is not reflected in LCOE calculations. Under alternative contractual arrangements, prices would be higher.

Building a system to reliably match supply with demand, using only VRE, requires a combination of overbuilding to raise the floor of output (when the wind does not blow and clouds obscure the sun), with the result that too much power is generated when the wind blows and the sun shines, and storage to shift power from when it is produced to when it is needed. Overbuilding raises the cost of useable power; reducing overbuilding requires more storage, which is expensive. The falling costs of VRE equipment, batteries and advances in new longer-term energy storage technologies promise to raise the limits to VRE grid penetration and reduce the need for gas back-up. But for now, when accounting for the need to meet the demand for power 24 hours a day, all year round, the costs for using only VREs and batteries are higher than when including some gas alongside them.[2]

In advanced economies, the debate often centres on when renewables and storage will out-compete gas 'peakers', which are less fuel efficient but are well suited to rapid ramping to meet peak demand, whether it is expected or unexpected. In many African countries, the need for reliable power tends to be so great it makes little sense to build a gas plant only to run it 20 per cent of the time. As a result, most gas plants are 'combined cycle' gas turbines, that cost more to build and cannot be ramped so quickly, but use fuel more efficiently. A typical tariff for such a plant using indigenous gas and running at 80 per cent capacity would be around 6-8 cents per kWh. That is two or three times more than the very cheapest, largest scale, 'take-or-pay' solar tariffs, similar to tariffs from medium-scale solar projects in more average regions, but two or three times less than what the tariff from a long discharge-duration solar and storage package would be.[3]

1 These LCOE numbers are the medians from a sample of plants worldwide, and there is a lot of variation from place to place, so which option is cheapest will vary with context.

2 In Section 3 of this report, we present some capital cost estimates for combinations of wind, solar, batteries and gas, sized to meet an example demand profile. We also present some cost estimates for battery energy storage systems.

3 This range for gas tariffs reflects market data supplied by CDC, which is not public. Solar and battery costing are based on estimates presented in Section 3 and are also consistent with prices for African independent power projects reported by CDC.

African governments facing the urgent need for more reliable power, multiple demands on their fiscal capacity and a limited desire or ability to pass on higher costs to users, are not likely to deviate far from least-cost technical solutions for the sake of accelerating decarbonisation. We cannot assume the international donor community will bear the costs of more rapid decarbonisation either. Chirambo (2018) estimates that Africa requires investment of between $41 billion and $55 billion per year to attain the energy access goals of United Nations Sustainable Development Goal (SDG) 7 *without* any requirement that all new power be sustainable. Current annual spend on energy sector development is estimated to be in the range of $8 billion to $12 billion per year.

Africa is different

The most important thing to recognise is that the challenges that Africa faces to decarbonise its electricity grids are fundamentally different to those of wealthier economies with mature energy infrastructure and relatively flat demand.

Most African countries are starting from a very low base, and must build up their power networks and generation capacity rapidly if they are to stand any chance of achieving their urgent development objectives. Most advanced economies face relatively flat demand, and are starting from a position of having sophisticated power systems with a fleet of fossil generation, which they can progressively decommission while adding VREs. Although demand for electricity is expected to rise in advanced economies with the shift to electronic vehicles and the electrification of heating, that is a very different situation from an African country wanting to multiply its electricity supply severalfold in a span of decades.

The typical African grid energy transition can therefore be thought of as 'vertical', because total output must rise rapidly. Mature economies, by contrast, face a 'horizontal' energy transition, in which existing 'firm' resources can be relied on to handle intermittency from greater reliance on VREs, while alternatives such as energy storage are added over time.

Figure 1 is an illustrative and simplified depiction of the transition to 100 per cent renewables, with a 'vertical' transition increasing total power output fourfold by 2050, and the 'horizonal' keeping it flat. In both cases, coal is decommissioned and the share of VRE in grid generation rises at roughly the same ambitious pace. In the 'vertical' case, this implies the addition of some gas generation in the medium term (even assuming 50 per cent renewables in 2030), whereas in the 'horizonal' transition all investment in new generation capacity is in renewables.

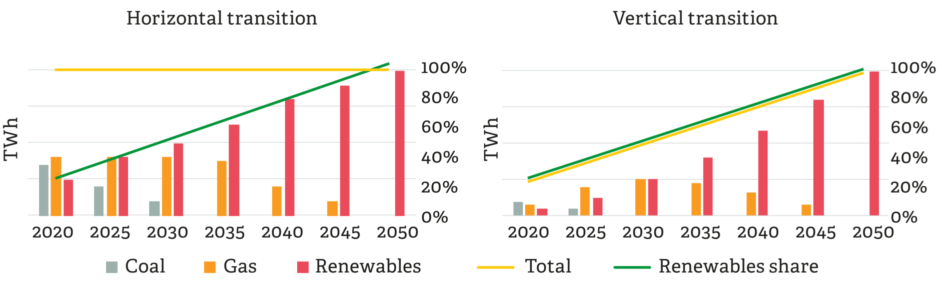


Figure 1: Stylised depiction of a horizontal (left) versus a vertical (right) grid energy transition

African countries can 'leapfrog' fossil fuels, in the sense that they can avoid going down the path of high dependence on fossil fuels, particularly coal and oil, that other countries followed. They can make far greater use of renewables and energy storage, and more quickly relegate gas to a peripheral role in maintaining the stability of electricity grids. Decentralised solutions will accelerate this transition. But that does not mean African countries can leapfrog to 100 per cent renewable grids.

Models of the electricity system transition in Africa that account for the need to achieve carbon neutrality by mid-century, and rapidly expand electricity generation for economic development, foresee the need for investments in a mix of generation technologies over the medium term. Under the most ambitious and stringent climate change control scenario, modelled by van der Zwaan, et al., (2018) the electricity power capacity additions in Africa between 2030 and 2050 are solar (24GW), wind (20GW) and gas (18GW), as show in Figure 2. Schwerhoff & Sy (2019) review five highly detailed, well-documented energy-economic models that allow for Africa to rapidly develop its economy (a several-fold increase in energy production) while respecting a 2-degree target.[4] These models differ in specifics but all foresee that a mix of VRE and 'firm' energy sources will be used, because some of these sources are complementary (such as gas and VREs) and also because locations for some vary.[5] After asking how Africa can generate energy for sustainable and equitable development, Avila, et al., (2017) reach the same conclusion.

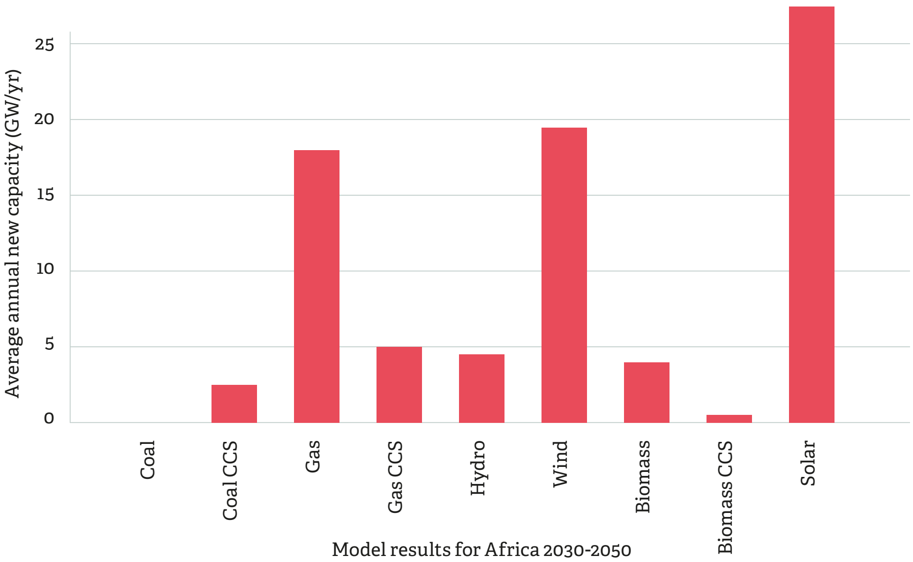


Figure 2: Future energy generation additions under the most ambitious climate change mitigation scenario in van der Zwaan, et al., (2018)

The global carbon budget has little room for new sources of greenhouse gas emissions, but if space must be found to accommodate Africa's economic development need, it should be found from wealthier economies accelerating the decommissioning of their fossil fuel facilities. The differential between levels of African power consumption and that of today's heavily industrialised economies is so great that the accelerated decommissioning of just a handful of the largest 5GW coal plants in countries such as China, South Korea, Germany and Poland would create ample room for African countries to retain their least-cost development pathways.

4 Keeping the CO2 concentration in the atmosphere below 450 parts per million (ppm).

5 The models also all rely on heavy use of biomass and fossil fuels combined carbon capture and storage, both of which are questionable assumptions.

Accelerating decarbonisation in Africa

Under the most stringent climate control scenario modelled by van der Zwaan, et al., electricity generation in Africa will be about 75 per cent renewables by 2050 (and most fossils generation fitted with carbon capture). The pace of decarbonisation would be hastened by faster than anticipated reductions in VRE costs, but Schwerhoff & Sy also note that higher shares of VRE emerge from models that include progress in technologies to deal with intermittency: making conventional power plants more flexible; creating more regional power pools; adjusting demand; and advances in energy storage. Schwerhoff & Sy conclude that if African countries can overcome some long-standing challenges to regional integration, regulatory reliability and inadequate infrastructure investment, grids running almost entirely on renewables should be viable by 2050.

The pace of progress towards this goal will vary across the continent. In this report we look at the situations in six countries (Nigeria, South Africa, Kenya, Tanzania, Senegal and Benin) in more detail, using information from national power strategies where available. Some of these countries are hoping to achieve levels of VRE penetration as high as 30 per cent by 2030, but progress will depend on the availability of dispatchable power – either hydro, geothermal, biomass or gas – and on the pace of investment in power networks.

Transmission and distribution networks remain relatively rudimentary in most African countries, constraining the ability to move low-carbon power from where it is best generated to where it is most needed, to import power when domestic renewable output is low, to export excess renewable energy output when it is high, and to integrate energy storage. Decentralised solutions offer the potential to sidestep these problems, but reliable centralised grids will still be needed to meet the needs of many productive enterprises, especially in large urban areas. The path to fossil-free grids requires sophisticated operational capabilities that are not yet widely found in the African context.

Advanced grid management capability—which includes sub-hourly dispatch and intra-hourly scheduling, Automatic Generation Control (AGC) and weather and plant power forecasting—is an absolute must for integrating high shares of renewable energy. Energy storage is also institutionally and operationally demanding. Regulatory models must reward batteries for charging in periods when renewables output is high relative to demand and discharging when it is low. Markets for other ancillary services that can also be supplied by batteries would also help generate revenues and recover costs. Even in wealthier countries, suitable regulatory models for integrating energy storage are a work in progress. Rapid improvements to operational capabilities can be made – as our case study of Senegal testifies – but the discouraging present conditions in many countries' power sectors cannot be waved away and nobody should assume the problems that have beset African utilities for decades will always be quickly overcome.[6]

African countries will not achieve their development aspirations, particularly SDG 1 (end poverty), SDG 7 (universal access to reliable energy) and SDG 8 (decent work and economic development) without a huge expansion in the supply of reliable and affordable grid electricity. African countries should therefore be supported in their efforts to achieve their self-determined, least-cost power sector development plans and future long-term decarbonisation plans under the Paris Agreement.

If the international community wishes to accelerate the pace of electricity decarbonisation in Africa, it should concentrate its efforts on supporting the investments that will bring forward the day when new investments in gas generation are no longer needed. Areas for support include regulatory and market reforms, early adoption of energy storage, national and international transmissions and distribution infrastructure, and improved power network management capabilities.

6 The political economy of power sector reform is complex and outside the scope of this report. Lee and Usman (2018) provide a survey.

01

Introduction

African countries need more reliable and affordable electricity to meet their development goals, and they must decarbonise electricity generation to meet their commitments under the Paris Agreement. The revolution in renewable energy means African countries can avoid the carbon-intensive electricity generation mix and centralised systems used by earlier developers. That does not mean they can leap straight to 100 per cent renewable generation on electricity grids. How quickly African electricity grids can go entirely fossil-free is a complicated question, and some features of African power networks make decarbonisation more difficult than for wealthier countries. The purpose of this report is to review the African context, and what will determine its pace of decarbonisation.

Africa bears almost no responsibility for the climate crisis. However, as African economies develop, the continent will be responsible for a meaningful share of global annual greenhouse gas emissions. Almost every African country has signed the 2015 Paris Agreement, and joined the effort to achieve net zero carbon emissions by mid-century. Twelve African countries: Djibouti, Democratic Republic of Congo (DRC), Gambia, Ghana, Kenya, Malawi, Morocco, Niger, Rwanda, Senegal, Sudan and Tanzania have targets of achieving 100 per cent renewable electricity generation on or before 2050 (REPN, 2020). More will no doubt join them.

Africa has no shortage of sunshine and wind, and opportunities for investment abound. But there are also challenges. This report starts by surveying the realities of African power networks, before discussing the technicalities of integrating intermittent renewable energy into the grid, and the costs involved. We will then look at the state of play in six African countries: Nigeria, South Africa, Kenya, Tanzania, Benin and Senegal. We close by discussing what can be done to accelerate the decarbonisation of African electricity. There is much to be done.

02

Africa's need for power

By 2050, one in four persons in the world will be an African, when the continent's population is forecast to top 2.5 billion (United Nations, 2020). African economies are growing relatively fast, but many countries are only just managing to keep ahead of population growth and although poverty rates are falling, the absolute number of people living in poverty is rising.

Economic and population growth has contributed an 85 per cent increase in electricity generation since 2000, but levels of access to reliable modern energy on the continent remain by far the lowest in the world. According to the International Renewable Energy Agency (IRENA), Africa's totalled installed generation capacity is estimated at 234GW, which is comparable to the capacity China added in just two years between 2017 and 2019 (IRENA, 2019). Today, Africa generates around 3 per cent of the world's electricity and just two countries, South Africa and Egypt, account for half of that. In some countries, the margin between installed generation capacity and power supplied is very wide. Nigeria reports an installed capacity of 13GW, but its ageing grid delivers only about 5GW to a population of 200 million.[7]

Only 44 per cent of the population in sub-Saharan Africa has access to electricity – but there is great variation across the continent, ranging from 9 per cent in Burundi and 11 per cent in Chad to 92 per cent in Gabon, and with most of North Africa achieving universal access (ESMAP, 2019). Average electricity consumption per person is around 500kWh in sub-Saharan Africa (excluding South Africa), which compares to about 13,000kWh in the US and 6,500kWh in the European Union.[8] A large American fridge uses about 1500kWh annually.[9] The London Underground consumes more electricity in four months than the entire nation of Benin, with a population of 12 million, consumes in a year.[10]

7 Financial Times (28 May 2019), Muhammadu Buhari's challenge to keep Nigeria's lights on.

8 World Bank: Electric power consumption (kWh per capita) - sub-Saharan Africa (excluding high income).

9 Energy Use Calculator (2020), Electricity usage of a refrigerator (retrieved July 20, 2020).

10 Benin generates around 0.3 terawatt hour (TWh) of electricity in a year, the London Underground uses around 1.2TWh. Sources: Benin Energy Country Profile and British Business Energy.

Universal access to affordable, reliable, sustainable and modern energy is a sustainable development goal in its own right, but it is also instrumental to others, especially the eradication of poverty and the creation of decent work and economic growth. These outcomes will not come about simply by supplying grid connections to the poorest households, which generally have more pressing demands on their incomes than purchasing electricity and are often unable to put power to productive use (as evidenced by Lenz, et al., (2017) and Lee, et al., (2020), for example). Rather, it is the provision of reliable and affordable power to industry and commerce that will drive the structural change to lift African economies out of poverty. The evidence linking reliable eletricity to job creation and the long-run productivity of firms is overwhelming.[11]

To attain any meaningful socio-economic development, Moss (2018) estimates that countries will need to raise their per capita consumption severalfold to about 1,500kWh. Models of Africa's future energy system assume African power generation will increase many times over before 2050 (van de Zwaan, et al., 2018). It is estimated that Africa will need investments of between $41 billion and $55 billion per year up to 2030, up from the current level of around $8 billion, if SDG 7 (access to affordable, reliable, sustainable and modern energy) is to be realised.

2.1 The current condition of African power networks

In 2015, sub-Saharan Africa countries experienced an average of 253 electricity supply interruptions totaling 741 hours of outage (Arlet, 2017). That same year Organisation for Economic Co-operation and Development (OECD) countries experienced an average of one interruption translating to a total of just one hour of outage (World Bank, Doing Business, 2016). Although the cost of electricity in Africa is the highest in the world, in 25 of 29 countries surveyed fewer than a third of firms reported having access to reliable power (Blimpo & Cosgrove-Davies, 2019). The economic cost of electricity supply interruptions is high. In one country alone, Nigeria, The International Monetary Fund (IMF) estimates that unreliable electricity results in economic losses of about $29 billion annually. The low quality of electricity has also resulted in the widespread use of private fossil fuel powered back-up generators, estimated to be about eight million units that emit upwards of 100 million tCO2/year, comparable to 21 per cent of total emissions from the formal power sector. In extreme cases such as in Nigeria, back-up generators produce CO2 emissions equivalent to 60 per cent of the total electricity sector. Most of these generators are in locations already covered by the electricity grid.

Most African utilities are loss-making and unable to apply cost-reflective tariffs, effectively collect payments, maintain reliable supply, minimise technical losses, and attract significant private sector capital needed for investment at scale. Power networks in Africa have very high distribution and transmission losses, which greatly increases costs (Blimpo & Cosgrove-Davies, 2019). The widespread inability of African utilities to perform the basic of functions involved in supplying electricity illustrates the scale of the challenges they will face to make the transition to more technically demanding intermittent sources of low carbon power.

11 See Cole, et al., (2018); Fried & Lagakos (2017) and (2020); Kaseem (2018); Mensah (2018); Abeberse (2017) and Lipscomb, et al., (2013) Eberhard, Dyson & Uttamchandani (2020) review the evidence for investing in power

The unit cost of electricity in many African countries is about double the global average ($0.14/kWh) and far higher than in many emerging economies such as Bangladesh ($0.06/kWh), and India ($0.08/kWh), excluding the added cost of back-up generation. Consumers in Liberia pay up to three times ($0.39/kWh) the average cost of electricity in the US ($0.13/kWh).[12] When compared to national income per capita, this disparity is even greater. The average Liberian lives on around $700 per year and it costs around 12 per cent of that to power a small fridge that consumes about 200kWh per year, which would cost of less than 0.1 per cent of average income in countries such as the UK, Spain, Sweden and the US (Global Petrol Prices, 2020; IMF, 2018).

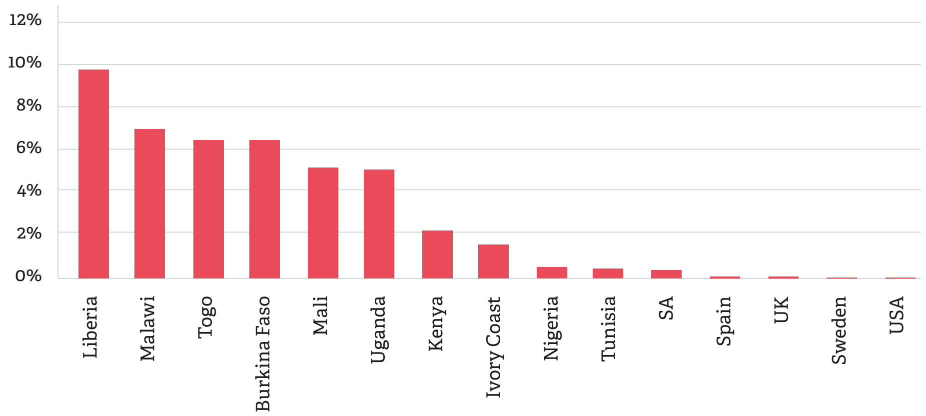


Figure 3: Cost of powering a fridge per year as a percentage of GDP per capita
Sources: GDP per capita figures - IMF 2019: https://statisticstimes.com/economy/countries-by-gdp-capita.php
Electricity prices - https://www.globalpetrolprices.com/electricity_prices/
Electricity prices (Liberia) - https://www.usaid.gov/powerafrica/liberia

All this puts most African countries in an extremely difficult position. The problems are daunting and the need for investment enormous, even without contemplating any additional technical difficulties and upfront costs to accelerate decarbonisation. Also, higher prices for electricity would have a major negative impact on the pace of economic development, access to basic services that require power (such as healthcare), and for the standard of living across the continent more generally.[13] African fiscal resources are under severe strain, with public revenues and foreign aid receipts per capita having fallen in recent years, and governments face many other urgent social demands (OECD, 2021). African governments will have extremely limited appetite to deviate from least-cost solutions for the sake of accelerating decarbonisation.

The good news is, of course, that renewable prices are tumbling and future energy systems with high shares of renewable energy have the potential to lower the cost of electricity generation (Oyewo, et al., 2020). Low carbon power sources also lend themselves to decentralised solutions that can be quicker and cheaper to build.

12 Global Petrol Prices (2020); Liberia Electricity Corporation (2020); US Energy Information Administration (2020).

13 Several African countries have national development plans that emphasise affordable and reliable electricity, including Kenya, Nigeria, Ghana, which each have 'Vision 2030', Rwanda has Vision 2050, and Senegal has the Emerging Senegal Plan (PSE) 2014-2035.

2.2 High renewable energy potential

Africa is blessed with excellent renewable sources of power, including wind, solar, hydropower and geothermal. The IRENA Global Atlas for Renewable Energy estimates an economic potential of up to 3,834GW for wind, 15,334GW for solar PV and 5,282GW for concentrated solar power (CSP) in 21 high-potential countries. IRENA estimates that Africa could meet nearly a quarter of its energy needs from clean renewable energy resources by 2030, and increase this to as much as two-thirds by 2050. The analysis did not foresee 100 per cent renewables, taking the view that appropriate renewable energy sources are not available in some countries, and integration will be constrained by transmission and distribution systems.

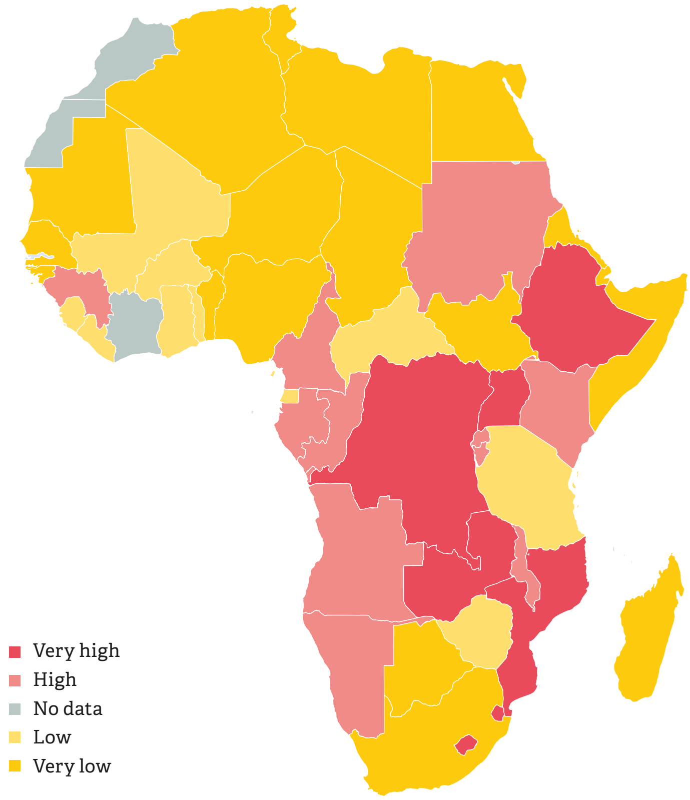


Figure 4: Contribution of renewable energy to installed capacity

Some Africa countries already have very high shares of renewable energy, thanks to excellent hydropower resources and, in places, geothermal (IRENA, 2019; see Figure 4). Sources of more reliable low carbon power such as hydro are extremely useful when designing stable power networks with high levels of intermittent power sources (wind and solar). Unfortunately, climate change is affecting rainfall patterns and increasing the frequency of droughts. Debilitating droughts in Kenya caused extended load shedding in 1999-2000. In Zambia, Trace (2018) estimates the drastic reduction in water supply led to a decline in generation capacity by up to 50 per cent. Many governments established fossil fuel fired emergency power supply units in response, some of which were maintained after the hydrology was restored.

2.3 High dependence on fossil fuel sources

Africa may have great potential for renewables, but electricity generation is today heavily reliant on natural gas and coal, contributing 46 per cent and 35 per cent respectively (BP, 2020). The countries with high levels of generation from renewables also tend to produce very little power overall, compared to the larger economies in northern Africa and South Africa that are dependent on fossil fuels.

Fossil fuels are both a source of power and national revenue. The continent holds 7.3 per cent and 7.2 per cent of global proven natural gas (509 trillion cubic feet) and oil reserves (125 billion barrels), with 38 per cent and 31 per cent of this capacity held in Nigeria alone. The fight against climate change demands that fossil resources are kept in the ground, but recent major discoveries in North Africa (Egypt), East Africa (Tanzania), West Africa (Senegal and Mauritania) and Southern Africa (Mozambique), which collectively accounted for over 40 per cent of global gas discoveries between 2011-2018[14] will inevitably impinge upon power generation investment decisions (IEA, 2019).

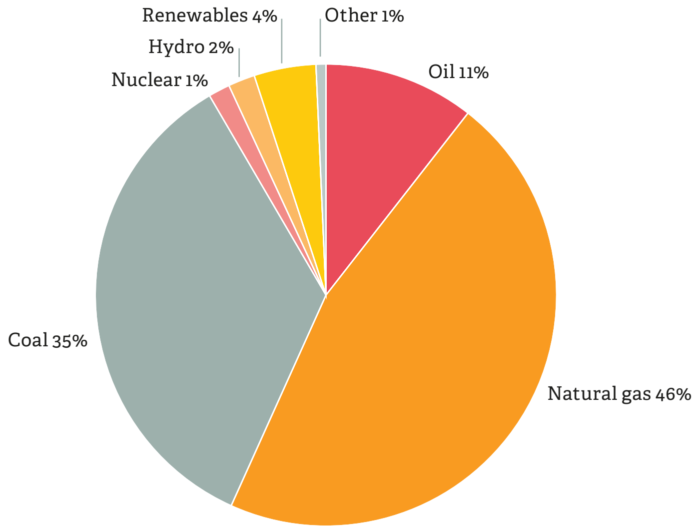


Figure 5: Source of electricity generated in Africa (BP, 2020)

2.4 Small, independent and disjointed energy markets

Most African energy markets remain effectively isolated, despite efforts to develop functional regional electricity markets (the Eastern Africa Power Pool (EAPP), Southern Africa Power Pool (SAPP), West African Power Pool (WAPP), Central Africa Power Pool (CAPP) and *Comité Maghrébin de l'Electricité* (COMELEC)), according to the African Energy Commission (2019).

Electricity sector planning predominantly occurs at the national level. This makes it harder to arrange large-scale inter-regional investments, and causes higher production and transaction costs, and counterproductive competition. The SAPP has been more successful, but the continent generally has had to contend with insufficient investment in shared generating and transmitting infrastructure, a lack of trust among states, nationalistic outlook to electricity planning and preference to bilateral agreements over regional ones (Byiers & Karaki, 2019).

14 IEA (2019), Africa Energy Outlook 2019, International Energy Agency, Paris.

This disjointed situation will not help the integration of higher shares of VREs, where the ability to move power over great distances to match supply with demand is especially important. More optimistically, several projects to physically integrate power markets in Africa are planned or are under development, including the following interconnectors: 1,010km Ethiopia-Kenya; 463km Kenya-Tanzania; 582km DRC-Uganda; 400km Mozambique-Zimbabwe; 500km Angola-Namibia; and 350km Mali-Guinea, among others (USAID, 2018). Some areas are projected to have surplus generation capacity (as show in Table 1) and a greater ease of trading power would enable more efficient generation investments.

	Eastern Africa		Southern Africa		Western Africa	
	Country	*MW*	*Country*	*MW*	*Country*	*MW*
1	Ethiopia	1898	South Africa	8769	Gambia	77
2	Uganda	108	Zimbabwe	512	Guinea Bissau	41
3	Kenya	698	Botswana	14	Niger	50
4	Rwanda	41	Mozambique	9	Nigeria	3545
5	Tanzania	686	Malawi	356	Benin	110

Surplus Deficit

Table 1: Projected surplus/deficit generation capacity by 2025 (USAID, 2018)

2.5 The contrast with wealthy economies

Many wealthier economies have set ambitious targets for transitioning away from fossil fuels. Sweden and Denmark aim to eliminate fossil fuel from electricity generation by 2040 and 2050 respectively, while Germany aims to generate 65 per cent of its electricity from renewable sources by 2030. In the US, California and New York have set targets of achieving net zero-emissions from the electricity sector by 2045 and 2040, respectively.[15]

The challenges of 'horizonal' renewable energy integration in rich economies with mature energy infrastructure and relatively flat demand are fundamentally different from those faced by African countries that are starting with poor quality infrastructure and the need to expand generation very rapidly.

Integrating intermittent generation sources requires back-up generation capacity and storage, flexible transmission and distribution infrastructure, and advanced grid management capacity based on automated or smart controls (Denholm, et al., (2015); World Bank ESMAP (2019); IRENA (2020). Rich countries with high decarbonisation ambitions are well positioned on these three dimensions, for example, Denmark, Sweden and Norway are supported by vast hydroelectric resources in the Nord Pool AS power exchange.

The UK is often praised for its rapid decarbonisation, having nearly eliminated coal and invested heavily in offshore wind, but it has gas-fired back-up installations contributing about 30 per cent of the national installed capacity and is still considering new gas power projects for 'firm' capacity. Germany has coal-fired back-up capacity contributing 20 per cent of installed capacity, which it is not planning to shut down until 2038, and remains the world's fourth-largest consumer of coal (Fraunhofer, 2020). With existing fleets of firm power generators, the challenge is to add VREs and storage while upgrading network management capabilities, to stay as close as possible to the technical frontier of maximum VRE penetration.

The flexibility of gas has proved especially useful in this process. Verdolini, et al., (2018) studied VRE integration between 1990 and 2013 across 26 OECD countries, and found that fast response gas generation accelerates the adoption of VREs. The study suggested that a unit increase in the share of fast-reacting gas generators was associated with a similar increase in renewable energy in the long run. It is important to distinguish *installed capacity* from *electricity*

15 New York State Energy Research and Development Authority (2018); California Energy Commission (2018).

generation when considering this finding. Installing new gas generation capacity does not imply always using it – the power network can run on renewable energy sources – while fossil fuels are used only as back-up to cover shortfalls and intermittency. Gas can also replace other more polluting fuels. A few African countries burn a lot of coal, but there is also heavy fuel oil to replace, not to mention all those private diesel generators.

In contrast to these wealthy countries, the African transition must be vertical. The whole system must be built up rapidly, and back-up systems developed almost from scratch. The need for some further investments in new gas generation capacity in some African countries follows the facts that African countries must rapidly increase generation capacity and that a maximum economically and technically viable ceiling to VRE penetration exists. In 2019 wind and solar combined accounted for 24 per cent of the electricity generated in the UK (BEIS, 2019). Suppose African countries could leap straight to the world frontier of VRE grid penetration and achieve 50 per cent. In an African country that wants to quintuple its power output, this implies that once 50% VRE penetration has been reached, half of new generation capacity must therefore be non-VRE. In countries that lack hydropower or other low carbon 'firm' resources, that means relying on gas.[16]

In wealthy economies, the debate is mostly about how quickly energy storage will displace gas 'peaker' plants for balancing variable renewable energy output. However, in an African country needing to rapidly expand electricity supply, gas will often perform baseload and 'mid merit' roles. The need for reliable power is so great that more fuel-efficient combined-cycle gas turbine (CCGT) plants that can provide power 24 hours a day, all year round, are chosen over open-cycle gas turbine (OCGT) plants designed to be used intermittently. The cost of gas generation is tied to fuel prices, and a CCGT plant is often needed to anchor the development of a domestic gas field. OCGT plants are more likely to be found today in northern Africa or South Africa, where they can play a supplementary 'peaker' role, or in countries with cheap gas and a high cost of capital, so that the low upfront costs of OCGTs are appealing. As African countries make the transition to net zero, we should expect to see gas infrastructure moving to provide peaking services before being eliminated altogether. Over time, gas infrastructure in other African countries should transition to a back-up role, and VREs and storage become competitive for 24 hours a day, year-round power.

In the absence of strict policies to enforce the transitional role of gas, investments in natural gas could delay decarbonisation by rendering renewable energy solutions (generation plus storage) uneconomic (McJeon, et al., 2014). The risk of path dependency implies that timelines to stop further investment into gas-fired plants – and to decommission existing fleets – should form part of national policy. Such commitments will affect the economics of investment decisions made today, because a shorter operating life will make some options less appealing. This would help tip the balance toward renewables. New investments in gas power should have time-bound operating lives, or they should be converted to low-carbon synthetic gas, such as green hydrogen.

With all these variables, discussions of natural gas as a bridge in advanced markets can take on a philosophical nature. But with the sustainable development of Africa at stake, this discussion must be grounded in reality, and not assume away the constraints that African governments face. Thurber & Moss (2020) estimate that current generation is so low that even if sub-Saharan countries were to *triple* their current electricity consumption overnight using natural gas, the additional emissions would represent less than 1 per cent of global emissions— while transforming the lives of hundreds of millions of Africans. But nobody would propose any such a thing – electricity generation could be tripled by VREs with hydro, geothermal or gas back-up. Twelve countries in sub-Saharan Africa (Djibouti, DRC, Gambia, Ghana, Kenya, Malawi, Morocco, Niger, Rwanda, Senegal, Sudan and Tanzania) have already set ambitious targets of achieving 100 per cent renewable electricity generation on or before 2050 (REPN, 2020).

16 Because generation infrastructure takes time to build, power system planners may need to start construction in anticipation of constraints on VRE penetration being reached.

03

What it takes to keep the lights on

As has already been alluded to, integrating high levels of variable renewable energy (VRE) is technically challenging. Here we summarise those challenges, before looking at the conclusions reached in power system modelling exercises.

The fundamental role of any power system operator is to ensure electricity supply exactly matches electricity demand, at every location and point in time, while ensuring voltage and frequency remain within specified bounds. Although power system planners and managers have always contended with variability and uncertainty, VRE sources pose novel integration challenges. They are non-dispatchable and non-synchronous, meaning their energy output varies according to external conditions—typically, the instantaneous wind and solar resource available—and the operator has no ability to ramp them up or down to maintain system stability. VRE sources also have relatively low capacity factors (the average expected output of a generator as a share of its theoretical capacity). Arndt, et al., (2018) observe that typically VRE penetration levels above 20 per cent have the potential to introduce integration challenges. Trembath & Jenkins (2015) suggest a rule of thumb supported by extensive literature that "it is increasingly difficult for the market share of VRE at the system-wide level to exceed the capacity factor of the energy source". For example, the capacity factor for wind is typically between 20 per cent and 40 per cent, while the capacity factor for solar PV ranges between 10 per cent and 25 per cent.

Power system flexibility is the key to integrating VREs (IRENA, 2018). Useful lessons can be drawn from the experience of countries that have already achieved high VRE penetration. First, an interconnected grid infrastructure with neighbouring countries is invaluable. Denmark has an interconnector capacity of nearly 120 per cent of peak demand (Danish Energy Agency, 2020), compared to South Africa, with approximately 16 per cent (South Africa Power Pool, 2020). Without massive investments in interconnectors, and the regulatory and market reforms required to use them, the prospects of integrating high shares of renewable energy on the grid in African countries that lack dispatchable generation (hydro, biomass, geothermal, gas) will be much reduced.

Second, enhanced forecasting and short-term electricity market mechanisms, such as intra-day trading and dispatch or day-ahead markets, are essential. This requires day-ahead simulation (24-hour forecasts), intra-day simulation (one to four-hour forecasts) and real-time simulation (tracking actual energy output). The power control centre in Denmark makes an updated forecast of the coming period after every five minutes and requires all generators (greater than 10MW) to submit an update of their output every five minutes. In comparison, Kenya's system operator makes hourly forecasts and does not receive generator forecast output in real time.

Third is the availability of flexible demand, generation and storage, which includes conventional dispatchable power generators, demand-response market protocols and storage technologies such as batteries, pumped hydro and power-to-gas. Time-of-use tariffs, incentive payments and penalties can manage peak-load demand. In the US, demand bidding and capacity auctions allow demand-response to directly compete with supply-side resources to provide contingency reserves and frequency regulation services (Hale, et al., 2018).

Most African centralised power networks are still a long way from having these advanced capabilities, and until they are acquired it is not realistic to expect very high levels of VRE grid penetration. Decentralised energy systems can sidestep these constraints in some contexts, but centralised systems will continue to be the main source of urban, commercial and industrial power.

There is an enormous amount of academic research into future energy systems and the transition to net zero emissions. A useful survey of 180 peer-reviewed articles on this topic discusses what is *feasible* (what is technically possible using current technology), what is *viable* (what is possible within socio-economic and environmental limitations) and the *trade-offs* (Hansen, et al., 2019). Most research articles focus on Europe and North America. One evaluation of 24 peer-reviewed articles finds that they overlook some or all the critical considerations when integrating high levels of VREs, including accurate energy demand forecasting, granular simulation of supply to meet demand (sub-hourly intervals), required transmission and distribution investments and essential ancillary services, and hence substantially underestimated the challenge of comprehensive decarbonisation pathways (Heard, et al., 2017). These conclusions are contested by other researchers (Brown, et al., 2018), who argue these considerations could be handled at low economic cost, but their argument is heavily dependent on data from Europe, and the African context is not discussed.

We believe that careful appreciation of the African context is often missing from academic studies of decarbonisation pathways. It is necessary to understand the assumptions that underly any conclusions about the viable pace of decarbonisation. Are regional power pools presumed to exist, and the existence of markets and appropriate regulations, or are large hydro projects assumed to be finished on time? When a technology is presented as affordable, does that conclusion rest on a complete picture of all the investments needed to keep the lights on year-round? What is assumed about the capabilities of the relevant government and private sector actors to develop a pipeline of projects of different sorts?

This said, the need for investment in a mix of energy sources in Africa is the consensus among energy experts. Models of the electricity system transition in Africa that account for the need to achieve carbon neutrality by mid-century, as well as rapidly expanding electricity generation for economic development, foresee the need for investments in a mix of generation technologies over the medium term. Under the most ambitious, and most stringent, climate change control scenario as modelled by van der Zwaan, et al., (2018) the electricity power capacity additions in Africa between 2030 and 2050 are solar (24GW), wind (20GW) and gas (18GW). Schwerhoff & Sy (2019) review five highly detailed, well-documented energy-economic models that allow for Africa to rapidly develop its economy (a several-fold increase in energy production) while respecting a two-degree target.[17] These models differ in specifics but all foresee that a mix of VRE and 'firm' energy sources will be used, because some of these sources are complementary (such as gas and VREs) and also because locations for some vary.[18] Avila, et al., (2017) reach the same conclusion, after asking how Africa can generate energy for sustainable and equitable development.

3.1 Decentralised solutions

This report is focused on electricity generation for transmission and distribution over a centrally managed grid, which will be necessary to supply reliable and affordable electricity to many of Africa's productive enterprises and large urban areas. But not every commercial and industrial user will be best served by a grid connection alone.

African countries have leapfrogged fixed-line telephony by rapidly building mobile networks, and they have leapfrogged in-branch banking by rapidly adopting mobile banking and mobile money. Leapfrogging is not an apt metaphor for the challenges of adding high levels of variable renewable energy to a grid, but decentralised models do offer the prospect of leaping over some of the constraints that grid operators face.

The interplay of centralised and mini grids is complicated. Losing large customers can undermine the economies of scale that grids benefit from, but generation and storage capacity distributed across mini grids can be grid connected and become a resource to the central system. The implications of decentralised power for the future of centralised grids are beyond the scope of this report, but it is clear that decentralised solutions have huge potential to accelerate the decarbonisation of electricity generation in Africa.

The mining industry is an early adopter. By some estimates, 23GW of generation capacity in Africa is dedicated to mining, and mines are often off-grid with their own heavy fuel oil (HFO) or other fossil fuel generators, making them prime candidates for solar-hybrid mini-grids.[19] Agriculture, cold storage and telecoms are also often well suited to mini-grids, and even some notoriously hard to decarbonise sectors (such as cement) also consume significant amounts of electricity which can now be produced more cheaply by solar.[20] Commercial landlords are also starting to use roof space to generate power, and solar panels are an increasingly common sight on shopping malls. In Nairobi, for example, three of the largest malls have large solar installations (the Galleria, Garden City and Two Rivers malls).

The process of commissioning smaller local mini grids can be quicker and easier than grid expansion, but in some countries, there are regulatory barriers that must be cleared – for example, some African countries prohibit private companies from supplying electricity to third parties. Otherwise, the pace of mini grid adoption is largely a function of solar PV and energy storage costs, which are falling rapidly. The future for mini grids in Africa is very bright.

17 Keeping the CO_2 concentration in the atmosphere below 450ppm.

18 The models also all rely on heavy use of biomass and fossil fuels combined carbon capture and storage, both of which are questionable assumptions.

19 Bird & Bird: Renewables for Mining in Africa.

20 Ohorongo Cement, a cement manufacturer in Namibia, has built a 5MW captive solar plant and BMW has announced it will buy aluminium produced by solar power from Emirates Global Aluminium.

3.2 Understanding the costs of generation options

As a rule, African countries will choose the least-cost options for fulfilling the different roles asked of power generation (baseload, mid-merit, 'peaker' and ancillary services). Increasingly, the lowest cost option is wind or solar. The average LCOE for utility scale solar PV and onshore wind is now often below gas (average LCOEs being $56/MWh, $50/MWh and $71/MWh respectively, according to IEA 2020 projections) and records for lower electricity pricing from solar and wind projects fall every year.[21]

LCOE attempts to capture the average cost of power produced by a generator over time, after including such things as financing costs, but it does not present a complete picture of the costs associated with different generation choices. The concept of enhanced LCOE has been developed to incorporate external costs associated with integrating VRE (see Emblemsvåg (2020), Timilsina (2020) and Shen, et al., (2020) for discussions). These costs are driven by the demands of accommodating periods where the output of VREs is unusually low for an extended time.

System costs associated with managing VREs (which contribute about 15 per cent of installed capacity) in Kenya are now estimated to require an extra $50 million per year (Mutua, 2020). In Senegal, the 158MW Taiba N'Diaye wind power station requires at least 80MWh of storage capacity to facilitate smooth integration to the grid (Africa Energy, 2019). These costs are not included in LCOE calculations, and are not paid for by the wind and solar developers, which are bidding for contracts at record low prices. In the UK, for example, large solar PV costs are projected to drop to £37/MWh by 2030, but when adjusted for these costs, this rises to between £48 and £66/MWh. Table 2 shows enhanced LCOE estimates (UK Department for Business, Energy & Industrial Strategy, 2020).

	Original LCOE (A)	Wider system impact (B)	Other impacts (C)	Transmission impacts (D)	Enhanced LCOE (A+B+C+D)
CCGT*	97	-92 to -41	18 to 36	-1 to 0	40 to 82
CCGT + CCUS**	84	-65 to -37	22 to 45	-2 to 0	63 to 80
Onshore wind	42	-5 to 7	6 to 28	6 to 10	59 to 87
Large solar PV	37	8 to 15	1 to 16	0	48 to 66
Offshore wind	45	7 to 17	1 to 10	5 to 13	62 to 82

* CCGT – Combined cycle gas turbine   ** CCUS – Carbon capture usage and storage

Table 2: Enhanced levelised cost ranges for plants commissioning in 2030 across six low-carbon generation scenarios – £/MWh (UK BEIS, 2020)

21 These LCOE number are the medians from a sample of plants worldwide. With significant variation from place to place, which option is cheapest will vary with context.

To illustrate the implications for investment costs, we now present a hypothetical and simplified example in which generation and storage options are chosen to have a high confidence of supplying a given quantity of power output. We base this on actual power supply data collected over a two-week period in November 2020 from VRE sources and dispatchable sources in South Africa (ESKOM, 2020). We use generation equipment cost estimates from a commonly-used public source, the US National Renewable Energy Laboratory (NREL)[22] and consider alternatives to a 2GW capacity natural gas generator that might be chosen to meet peak demand of around 1.7GW (a demand pattern shown by the red line in Figure 7A).[23] A CCGT plant of that capacity might cost between $1.6 billion and $2 billion to build.[24]

Either wind or solar of the same 2GW capacity could obviously not be relied upon to meet peak demand, and the two combined alone (4GW) will still experience supply deficits (the capacity gap area marked in yellow in Figure 7B). There are three broad ways an energy policy planner could address the deficits shown in Figure 7B.[25] First, they could massively overbuild wind and solar capacity. In Figure 8, Option 1, we consider a scenario where wind and solar have been overbuilt by 600 per cent. This would be massively wasteful in isolation. In a large power pool excess power could be moved to where it is needed. As Arndt, et al., (2019) explain: if marginal additions to system VRE-generating capacity produce electricity when there is very little demand, that investment mainly adds to total systems costs without contributing materially to the provision of the actual energy services.

Second, energy planners could overbuild wind and solar, and add batteries to shift the supply surplus to when there is a supply deficit. Our example scenario in Figure 8, Option 2 deploys 5GW each of wind and solar plus battery storage with 0.5GW of total power output capacity. We chose battery storage at 5 per cent of installed capacity, because Mallapragada, et al (2020) find that, with VRE penetration at 60 per cent, storage is cost-effective until its capacity reaches 4 per cent of peak demand. This helps bring costs down somewhat, but only modestly reduces the need to overbuild.[26]

Third, energy planners could combine wind, solar, batteries and gas at 1.2GW capacity, to be used only as a 'peaker' when VRE and battery output does not meet demand. This is the scenario we imagine in Figure 8, Option 2. The low capital cost of some gas-fired units means they can recover initial investments even if they run a relatively low percentage of the time, due to high wind and solar shares.

22 US NREL OpenEI datababase provides the minimum and maximum overnight cost of investment per technology ($/W installed) as at 2020. We use both values to show the possible range.

23 Dispatchable sources such as geothermal, coal, gas and large hydro have a similarly steady supply curve. The demand curve, also known as the load curve, is a graphical depiction of the variation in power demand over a time period. All the 2020 overnight capital cost estimates are obtained from the OpenEI initiative of the US National Renewable Energy Laboratory (NREL) and the US Department of Energy (DoE). Overnight capital cost is the initial cost of a generation technology per kilowatt of capacity, if it could be conducted overnight. Estimate cost of batteries obtained from NREL (2020).

24 Based on IEA data on market information disclosed by CDC.

25 Seasonal solar variation is relatively small in Africa, but wind or solar output might still vary considerably over a year, depending on the local climate, as may demand. In a more realistic setting than this illustrative exercise, planners would have to design supply to meet demand under more extreme variations than evident in the two weeks of data we are using here.

26 If a power system planner was asked to match supply to this demand pattern using only wind and solar generation, the optimal solution could involve more storage and less overbuilding. The results in Mallepragada, et al., (2020) suggest this is a reasonably realistic scenario but we have not performed a cost minimisation exercise.

Upfront capital costs can be important in those African countries where the cost of capital is significantly higher than faced in wealthy countries (and that is assumed in some LCOE calculations). Installed capital costs vary greatly with context, as the wide range of costs reported by organisations such as IRENA and NREL testify. Engineering, procurement and construction (EPC) can be more expensive in some African countries because of security and infrastructure issues, resulting in fewer and smaller projects. Media reports can give an incomplete picture because record low prices are more newsworthy. Based on a set of public sources and market prices reported by CDC, we take a reasonable range for typical installed capital costs today to be $850-$1100/kW for utility-scale solar PV, $1400-$2100/kW for wind, $800-$1000/kW for CCGT and $600-$800/W for OCGT.[27] That would imply capital costs for Option 1 (wind and solar) the range of $13.5 billion to $19.2 billion, Option 2 (wind, solar and batteries capital costs in the range of $11.8 billion to $16.7 billion and Option 3 (wind, solar, batteries and gas) costs in the range of $5.8 billion to $8.1 billion.

Of course, upfront costs do not include operating costs, and once the cost of fuel is included the lifetime operating cost of gas power will be closer to that of wind and solar. We look at all-in cost comparisons for gas and battery energy storage systems in the next section.

In these examples we (crudely) sized generation capacity to hit a minimum power output, whereas an LCOE calculation gives the cost of power from a generator averaged over its lifetime, even if some of that power is paid for but not needed. Options 1 and 2 produce more power than needed, which is why they are most expensive. As storage prices fall, the extent of overbuilding needed in a pure VRE solution will also fall. And, as the costs of solar PV panels and wind turbines fall, overbuilding will become less costly too. The outcome of procurements underway in South Africa, in 2021, where bidders have been asked to meet given demands, promise to give an idea of up-to-date relative costs for different configurations of generation and storage.

Figure 6: Power supply from 2GW wind and 2GW solar PV

27 Data on costs taken from Timilsina (2020), Irena (2020b), IEA Projected Costs of Generating Electricity - 2020 edition and NREL Solar Installed System Cost Analysis – Utility Scale PV.

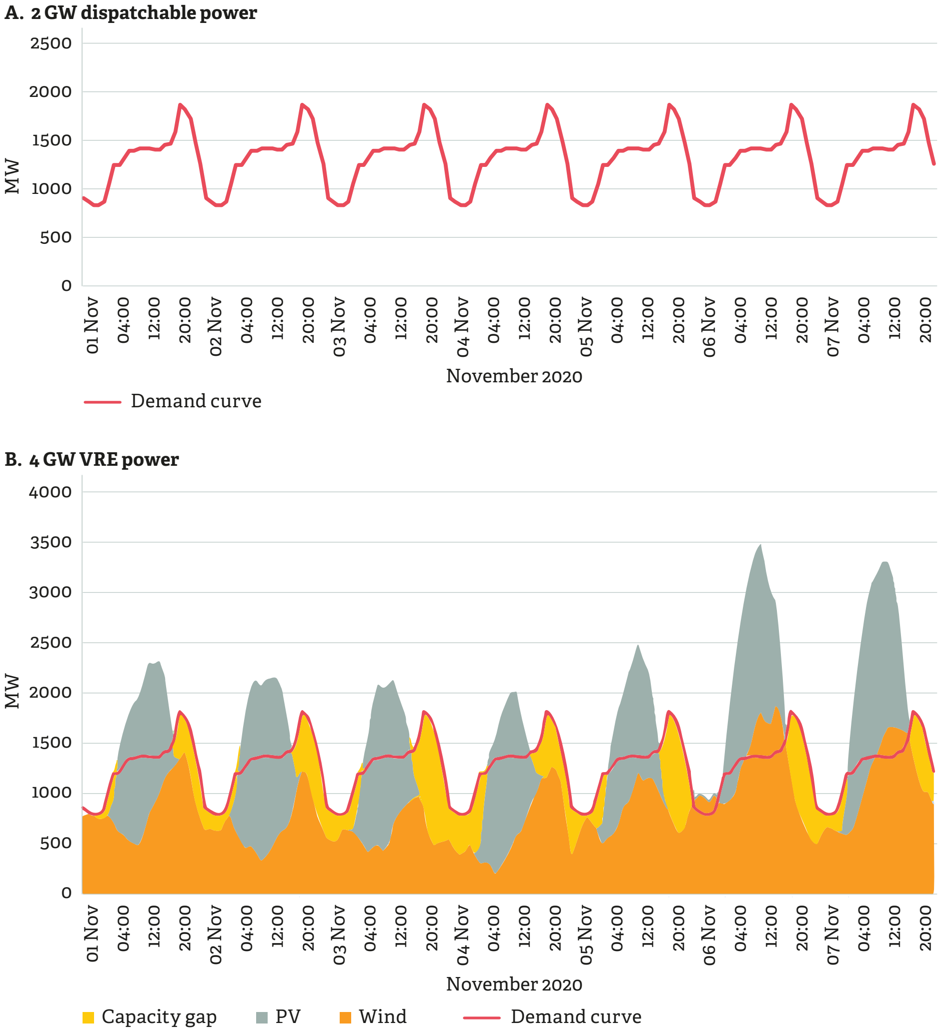
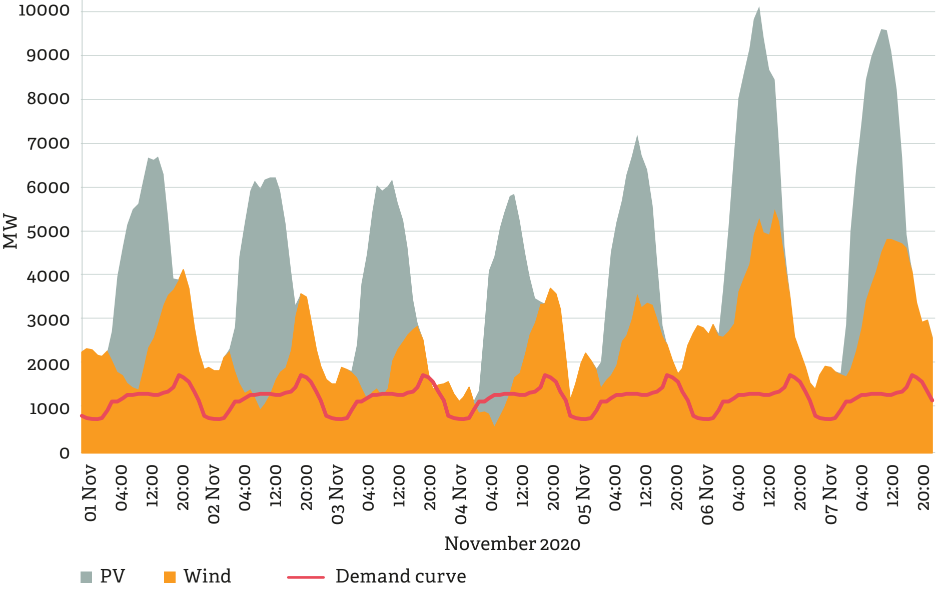
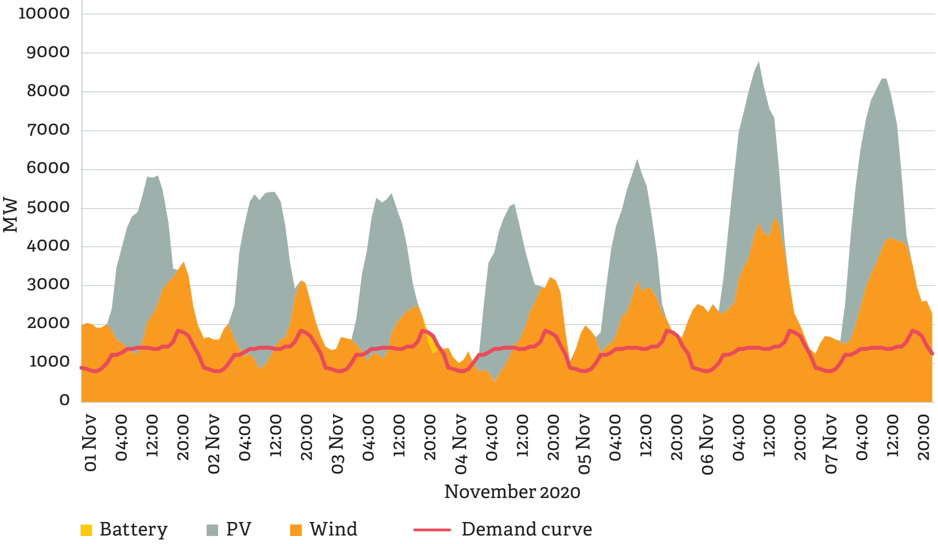


Figure 7: Comparing 2GW dispatchable power with 4GW of VRE

Option 1: 6 GW solar PV + 6 GW wind



Option 2: 5 GW solar PV + 5 GW wind + 0.5 GW batteries



Option 3: 2 GW solar PV + 2 GW wind + 1.2 GW gas + 0.2 GW batteries

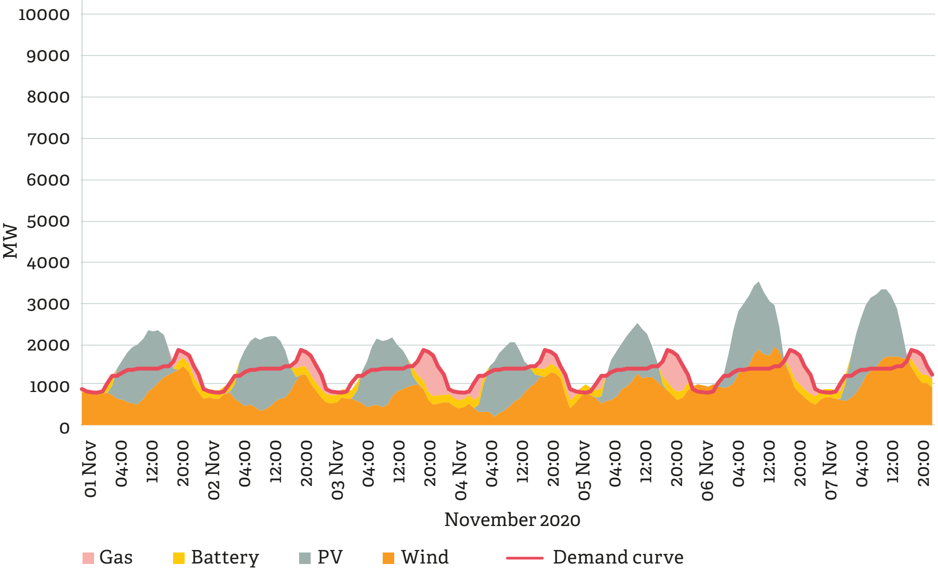


Figure 8: Comparing Option 1, Option 2 and Option 3

3.3 Battery energy storage systems

As technologies advance, and economies of scale bring costs down, storage combined with wind and solar are expected to become the most cost-effective means of performing many of the functions currently performed by gas (and other 'firm' power sources) by 2030, according to Wood Mackenzie (2020).

Cost is only one consideration. The unique capabilities of different technologies are the other half of the story: what do you get for your money? This section discusses these unique capabilities and compares gas-fired power plant and battery energy storage systems (BESS). We start with the basic function of supplying power, before discussing ancillary services such as voltage support and frequency regulation.

Sepulveda, et al., (2018) caution that batteries do not provide a like-for-like substitution for clean firm power sources, such as gas with carbon capture, as power systems approach 100 per cent renewable in 'deep decarbonisation' scenarios. As already mentioned, African countries with indigenous or other sources of cheap gas will often be looking at CCGT plants with tariffs in the region of 6-8 cents per kWh and the ability to supply power 24 hours a day. A CCGT plant can be built with multiple turbines, and some of these can be run as OCGT as needed. As African grids develop, and the costs of renewables and storage continue to fall, we can expect gas to play an increasingly peripheral role in meeting peak demand. A straight cost comparison for an OCGT gas peaker against BESS for a given discharge duration does not recognise the flexibility of gas being able to supply power as needed without time limitations.

In California, BESS competes with gas peakers to provide firm capacity for four hours, typically from 6pm to 10pm, and it has become common to compare costs on that basis.[28] Of course, electricity is needed after 10pm, and power planners must also manage seasonal variation in demand and be able to cover extended periods in which wind and solar generation are unusually low. Although these questions can be deconstructed into determining the cheapest way to perform various discrete functions, the real problem faced by planners is one of overall system design. For that, flexibility – the ability to perform different functions as needed – is extremely valuable. This is especially so for utilities across Africa that must regularly deal with supply uncertainty due to an ageing infrastructure that frequently underperforms. Climate variability is also increasing the need for flexible back-up in countries with previously reliable hydrology.

Nonetheless, to provide some cost comparisons between BESS and gas, we draw from research carried out in California to assess the technical and economic attributes of a 50MW solar PV plant coupled to a 60MW battery, and a 70MW gas peaker for providing three-hour firm capacity.[29] The researchers use a metric called lifetime cost of operation (LCOO) to capture the installation and operating costs over the project lifetime, in relation solely to the energy production during the target period (four hours).[30] Solar and battery systems have high installation costs but low operation and maintenance costs, while gas plants have low installation costs but high

28 California has 20-25 per cent of power produced by renewables and electricity prices are already negative during hours of peak solar production. It has around 21GW of fossil-fuelled peaker capacity.

29 Roy, et al., (2020). The BESS solution is specified as four-hour because that is needed to achieve a high 98.5 per cent capacity factor during the three-hour target window.

30 The more usual LCOE would be an average including any ancillary and power services provided outside the targeted peak hours window and would also include financing costs. In African countries facing higher costs of capital, LCOE would be higher than LCOO for more BESS with higher upfront capital cost and lower operating costs.

operation and maintenance costs. It is therefore prudent to consider both when doing a cost comparison. On the cost front, the lifetime cost of operation for a 50MW solar plant coupled to a 60MW/240MWh battery before tax credits was $162 million, somewhat higher than gas at $147 million.[31] However, the research these cost estimates are based on is over a year old. At the rate storage prices are falling, we should expect BESS to be cheaper than gas for shorter duration peaking services soon, if it is not already.

S. No	Cost parameter	50MW PV, 60MW/240MWh BESS	70MW OCGT
1	Plant lifetime	20	20
2	Target period capacity factor (4 hours)	98.5%	95%
3	Total system installed cost (2018, $)	$132M	$79M
4	Lifetime fixed operations and maintenance (O&M) costs	$19.6M	$43.8M
5	BESS extended warranty payment at $2/kWh	$10.8M	-
6	Lifetime variable O&M costs	-	$3.1M
7	Lifetime cost of fuel	-	$21M
9	Lifetime cost of operation (LCOO) without 30% investment tax credit (ITC)	$162.4M	$146.9M

Table 3: Lifecycle cost of operation for coupled solar PV with BESS and an OCGT in California (Roy, et al., 2020)

The situation changes when an eight-hour scenario is considered. While Roy, et al., (2020) did not model an eight-hour scenario, the cost for the solar and battery system and the OCGT can be estimated. For solar plus storage, the cost for battery racks and warranty must be doubled, but the costs for balance-of-system components and installation increase to a smaller extent. For the OCGT, only fuel and variable operation and maintenance costs double. Now the solar and battery system is at $282 million and the OCGT at $171 million, which is 60 per cent of the solar plus battery cost.

Roy, et al., (2020) design these two systems to provide energy in a certain target period each day, which results in a capacity factor of only 7 per cent. Based on the energy provided in that target period over the plant lifetime, the costs can be expressed as an LCOE. These would be 53 cents per kWh for the system with a four-hour and 46 cents per kWh for an eight-hour BESS (assuming a 10 per cent weighted-cost of capital). The respective OCGT LCOEs would be lower at 48 and 28 cents per kWh to deliver the same required energy.[32]

31 Solar plus storage is cheaper for the developer after accounting for 30 per cent ITC. Our focus in this report is on the overall cost to African countries, whether recovered from users or paid by tax credits from central governments. Some African countries offer favourable tax regimes for renewables (such as lower import duties) but we are aware of no equivalents to the ITC.

32 These and other LCEO estimates in this section are the author's calculations, peer reviewed and available on request.

However, the solar and battery system produces much more energy than required in the target period. If the total energy produced could be marketed, LCOEs would fall to 15.5 cents per kWh for the system with a four-hour and 13.5 cents for the eight-hour BESS. The corresponding LCOEs for the OCGT would then be higher at 18.8 cents per kWh for four-hour, and slightly lower at 12.9 cents per kWh for eight-hour.

This is a theoretical maximum utilisation of the BESS – it implies 512 cycles (charging and discharging more than once per day) – not a pattern of supply matched to real world demand. Power planners' need for 'long term storage' does not only mean batteries that can supply power for a longer period (for eight rather than four hours), but also the need to store energy for longer periods so there are longer gaps between charging and discharging. If eight hours of power is needed for rare occasions when even the most flexible system cannot match supply to demand for that long, the batteries might only be used a handful of times per year. If the eight-hour BESS performed only half a dozen cycles per year, the LCOE would skyrocket to 990 cents per kWh. A resilient grid requires flexibility and relying on BESS for that means having energy for occasional use stored for long periods in expensive batteries. This is why modelling exercises find that costs increase in a non-linear fashion the closer the grid gets to 100 per cent VRE generation, and it is for less-frequently used back-up that the combination of low upfront capital costs and variable fuel costs makes gas cheaper.

S. No	Cost parameter	100MW PV, 60MW/480MWh BESS	70MW OCGT
1	Plant lifetime	20	20
2	Target period capacity factor (8 hours)	98.5%	95%
3	Total system installed cost (2018, $)	$241.1M	$79M
4	Lifetime fixed O&M costs	$19.6M	$43.8M
5	BESS extended warranty payment at $2/kWh	$21.6M	-
6	Lifetime variable O&M costs	-	$6.2M
7	Lifetime cost of fuel	-	$42M
9	LCOO without 30% ITC	$282.3M	$171M

Table 4: Lifecycle cost of operation for an 8-hr AC-coupled solar PV with BESS and an OCGT in California (Author's adaptation from Roy, et al., 2020)

Away from the extremes of rarely-used storage, more typically in Africa, based on estimates from an open energy storage costing tool, we might expect tariffs from solar coupled with storage at 20-25 cents per kWh for systems with four-hour discharge (such as lithium-ion) and 17-22 cents per kWh for eight-hour discharge (such as vanadium redox-flow).[33] This is higher than the results of Roy, et al., and widely cited estimates from Bloomberg New Energy Finance of 15 cents per kWh for a 4-hour battery, which is likely due to the fact that Africa is subject to higher EPC costs and a higher cost of capital.[34] These estimates are for solar and battery systems where all solar energy is stored in the battery. It is common to develop systems where only part of the solar energy goes through the battery and the rest is sold directly. In these systems, the low LCOE of solar will 'subsidise' the battery cost, such that the combined LCOE will be lower.

Power planners will often want shorter duration, more frequently used storage. The more modular nature of solar and storage, which allows capacity to be added in smaller increments, will make it preferable to gas, which operates on a larger scale, in some cases. Other functions such as ancillary services will also sometime play a role in decisions. Costs also vary greatly with context, as the wide ranges reported by NREL and others reveals. Claims about whether gas or BESS is cheaper for performing certain roles should be interpreted as describing what is most often true, not always true. With these caveats, we can say that when the ability to supply power on demand over longer periods of time is needed, then BESS is still typically still substantially more expensive than gas.

To illustrate how the cost-effectiveness equation changes with the demands placed upon energy storage, a recent study from Zieglar, et al. (2019) in the US estimated that energy storage costs would need to reach $20/kWh for a 100 per cent wind and solar system to be cost competitive. However, if just 5 per cent of power was supplied by a firm resource (such as gas) a price of $150/kWh for energy storage would be low enough to make that the lowest-cost solution.[35] The NREL 2020 utility-scale battery storage four-hour duration cost projections for 2030 are $144/208/293kWh (low/medium/high) and $88/156/219kWh for 2050.[36]

Until storage costs have fallen to the levels suggested by Zieglar, et al., the closer the grid gets to 100 per cent renewable generation, the more overall system costs rise in comparison to having a mix of generation sources. There will not be a single point at which BESS becomes cheaper than gas for supplying dispatchable power. Rather, BESS will become the cheapest option for performing an increasingly large set of roles, relegating gas to rarely used back-up, until (with the help of emerging long-term storage technologies) additional gas generation will no longer be needed in Africa.

Besides the basic function of supplying power to satisfy demand, both gas and batteries provide various ancillary functions that increase grid reliability, over different timescales, as shown in Figure 9. Ramping reserves are needed for periods between a few seconds to a few hours, whereas firm capacity can be called on in timescales ranging from a few minutes to years.

33 Energy storage cost components based on Schmidt, et al., (2019).

34 Bloomberg NEF: Scale-up of Solar and Wind Puts Existing Coal, Gas at Risk.

35 These estimates are from Ziegler, et al., (2019). Battery prices in kWh refer to the price of a battery that stores a kWh of energy, with a certain combination of capacity and duration. Batteries offering different combinations of capacity and duration for the same kWh would come at different prices, and some quoted battery prices may also include installation and other costs, making price comparisons difficult.

36 OSTI Cost Projections for Utility-Scale Battery Storage: 2020 Update.

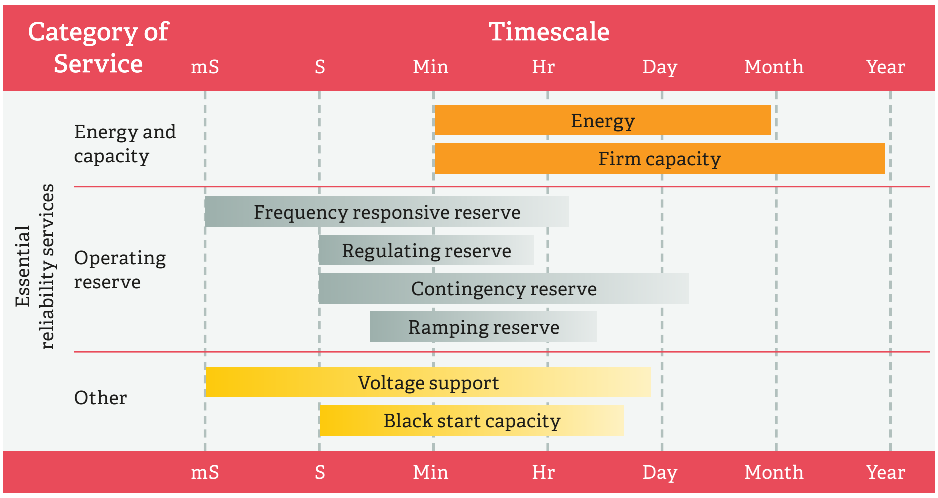


Figure 9: Main types of ancillary services (revised from NREL, 2019)

An imbalance between demand and supply can cause system frequency to rise or fall beyond the allowable limits. Batteries are especially well-suited to the job of providing frequency response and regulation. Batteries have proven they can deliver reliability and stability over small timescales (seconds to minutes) and medium timescales (minutes to hours) cost-effectively. After the opening of markets to batteries in Western Europe, Australia and the US in recent years, batteries are now becoming the dominant technology for ancillary services in these countries.

3.4 The future of storage

Bloomberg New Energy Finance estimates that the cost of lithium-ion batteries fell 87 per cent between 2010 and 2019 and further dramatic cost reductions are expected. Lithium-ion batteries are the cheapest option today for short-run storage, but some existing alternatives, such as vanadium flow batteries, may eventually become cheaper. Scientists are continually inventing new and refining old battery technologies. For longer-run storage, there are various candidates, including compressed air, molten salts, gravity (building towers or moving weights uphill), and using excess power to produce hydrogen that can be stored and used to generate power later (either in turbines or fuel cells). Some of these are still in the pilot stage.

One of the most optimistic future energy system modelling exercises (Ram, et al., 2019) finds that a global transition to 100 per cent renewable by 2050 is feasible and cost effective, with massive investments in batteries and gas being used for seasonal energy storage, but with natural gas replaced by synthetic or hydrogen over time. The gas turbines sold today can burn a mix of hydrogen and natural gas and, with a small amount of capital expenditure, can be converted to burn pure hydrogen. It would be unfortunate if wealthy countries availed themselves of the opportunity to switch to green hydrogen at low cost by using existing gas generation infrastructure, and Africa did not. The future of storage technology is uncertain, but many assessments regard hydrogen as mostly likely the cheapest for long-term applications (Schmidt, et al., 2019).

3.5 Constraints on storage

Batteries also pose specific challenges due to the nature of African electricity markets and the capabilities of utilities. Diurnal storage – charge during the day using solar PV, discharge at night – is relatively simple, but more flexible use of storage can require high-resolution forecasting capacity for both supply and demand. Most utilities in Africa do not have that capability. Few utilities anywhere in the world have experience of operating utility-scale batteries that store large quantities of energy relative to the size of the total electricity supply. China, the US, Germany, Australia, Japan and South Korea currently have the largest stocks of utility-scale batteries, but in all these countries batteries represent around just 1 per cent of total installed capacity (US Department of Energy, 2020).

In addition, batteries generally need multiple revenue sources to be financially viable ('value stacking'), including payments for both energy provision and ancillary services. These multiple value streams are simply not available in most African electricity markets. That can be expected to change, as the increasing attractiveness of batteries makes the necessary market reforms likely.

Relative to other technologies, batteries are an emerging technology and many utilities and regulators around the world lack the experience of integrating large shares of batteries effectively (NREL and USAID, 2019). African countries may be reluctant to take the lead in experimenting, when the most pressing imperative is the supply of ample, reliable, and affordable power.

04

Country case studies

Everything discussed so far in this report only becomes concrete in the context of African countries struggling with these challenges. In this section, we present a set of case studies showing how African countries find themselves in different situations, as they try to meet their developmental needs while meeting their commitments under the Paris Agreement.

4.1 Nigeria: Eyes on the power state

GDP – Nominal ($ billion)	447.8
Population (million)	202.0
Electricity generation capacity – total (GW)	13.7
Electricity generation capacity – renewable energy (%)	15.6%
Electricity consumption per year – total (GWh)	27,000
Electricity consumption per capita (kWh)	133.7

Nigeria is a federal republic with 36 states and one federal capital territory. Each state has an endearing nickname. For example, Gombe State is the “Jewel of the Savannah”, Kaduna State is the “Centre of learning” while Bayelsa State goes by “Glory of all lands”.

Niger State is known as "The power state". Like the country, Niger State gets its name from the River Niger, which is the third longest river in Africa after the Nile and Congo. It is home to three hydropower plants with a combined nameplate capacity of about 2GW. Could the keys to a fossil fuel-free Nigeria power sector lie here? Nigeria's exploitable hydropower potential is estimated to be above 18GW.[37] In 2018, the Ministry of Energy announced the restart of the highly controversial 3GW Mambilla hydroelectric power project in the Taraba State, with financing from the Chinese government.[38] This project has been in the making for over 40 years.

Nigeria is Africa's biggest oil producer, and its electricity generation is heavily dependent on fossil fuels, which accounts for 10.3GW or 82 per cent of total installed capacity. Grid-connect VRE sources are estimated to contribute a tiny 5MW. There is enormous potential for solar and wind in the north, but these resources are distant from the large load centres in the south, such as Lagos, Ibadan, Benin City, Port Harcourt and others as shown in Figure 10. Nigeria also has the largest natural gas reserves on the African continent.

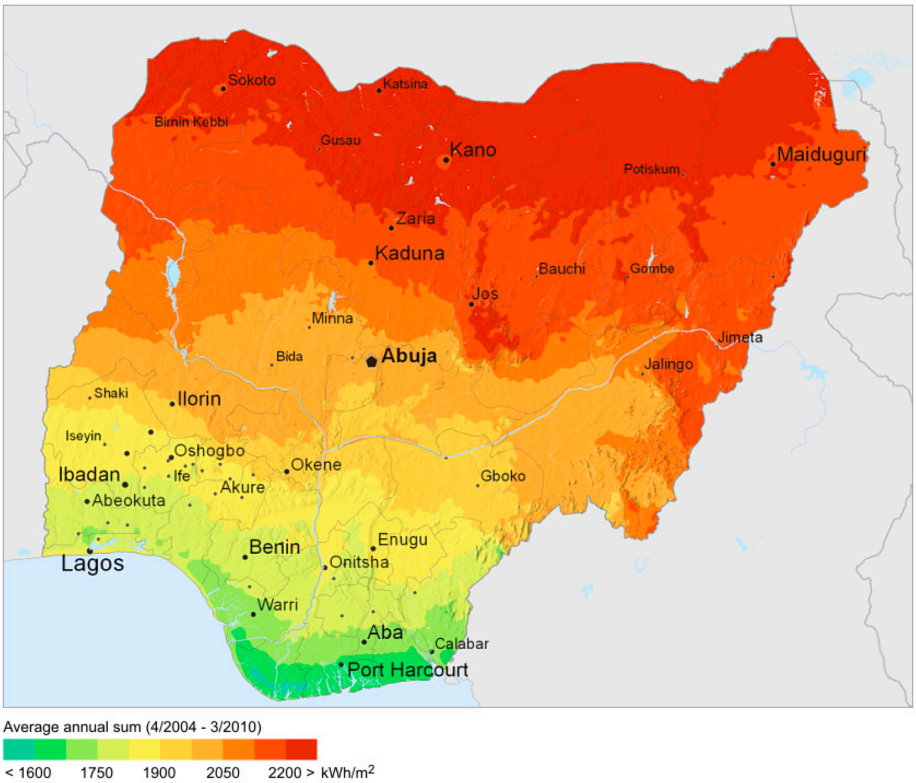


Figure 10: Global Solar Irradiation for Nigeria (Solar GIS, 2011)

Nigeria is Africa's largest economy, and its population is expected to double by 2050, reaching 400 million and making it the third most populous country in the world (UN, 2019). Despite Nigeria's vast power generation potential, its power sector is in a parlous state. Nigeria has 13GW of power generation capacity, but the ageing grid delivers only about 5GW to a population of 200 million (IMF, 2019). This staggering shortfall means those who can afford them rely on private petrol and diesel generators. An estimate 14GW capacity exists in small-scale diesel and petrol generators, and nearly half of all electricity consumed is self-generated (Akanonu, 2019). The IMF estimates the country loses $29 billion annually due to electricity supply limitations.

37 Adebayo, C. (2014), How is 100% renewable energy possible for Nigeria?

38 Hydro Review, Ingram, E. (2017), Nigeria approves contract to build 3,050-MW Mambilla hydropower plant

A myriad of challenges faces the power sector in Nigeria, the biggest among them being dilapidated infrastructure and poor financial health across the power value chain (Akanonu, 2019). More robust and modern grids in developed countries face the challenge of integrating high shares of variable renewable energies – the ageing and fragile grid in Nigeria places severe constraints on what is possible. In an attempt to turn this situation around, the power sector was unbundled in 2013, and generation and distribution was privatised. There are now six generating companies, 11 distribution companies, and one transmission company. But the consensus is that the privatisation has failed to bring improvements in the delivery of electricity services, with service coverage expansion, metering, quality of supply, load shedding and customer satisfaction all performing poorly (Idowu, et al., 2019).

Recently, the Federal Government of Nigeria has signed a hugely ambitious agreement with Siemens AG, a German multinational conglomerate, to upgrade the generation, transmission and distribution infrastructure through a phased approach (Siemens, 2019). The first phase will be the rehabilitation of transmission and distribution, a focus on reducing energy losses, and medium-term goals of 7GW and 11GW of reliable power supply by 2021 and 2023. Last year, the World Bank also authorised a $750 million Power Sector Recovery Operation (PSRO) to improve the reliability of electricity supply.

The dilapidated grid makes off-grid and mini-grid solutions even more attractive for both domestic and industrial applications. Nigeria has well-developed legislation dedicated to micro-grids and the government is supportive of the sector. In 2019, Nigeria inaugurated what was at the time the largest 'hybrid' plant of its kind in Africa, at Bayero University Kano, combing 3.5MW of solar, 2.4MW of back-up generators and 8MWh of storage. The project is part of an 'Energizing Education Programme', intended to eventually reach 37 universities and seven teaching hospitals, and to displace hundreds of diesel generators. The private commercial and industrial mini-grid market in Nigeria is a bright spot in the country.

An IEA report written in 2018 concluded that to provide electricity to its massive and growing population, Nigeria will need to draw intensively not just on renewable energy but also increasingly on domestic gas reserves (Occhlall and Falchetta, 2018). Through the Ministry of Power, Works and Housing, the Federal Government is planning on growing national generation capacity to 161GW with fossil fuels (mainly gas) contributing about 57 per cent of this capacity as shown in Figure 11 (Federal Republic of Nigeria, 2019). Hydropower is projected to contribute about 8.4GW (more than 80 per cent of the estimated national potential) and VRE sources 25.9GW (or about 16 per cent of total generation capacity) by 2030. Such high VRE penetration of distribution infrastructure, which is struggling to deliver 5GW of dispatchable electricity, will call for a complete remodelling of the transmission and distribution system, alongside extending access to almost half the population who are yet to be connected to the grid.

Part of this plan seeks to address the problem of gas flaring which, according to the country's Nationally Determined Contribution (NDC) under the Paris Agreement is a leading source of greenhouse gas emissions (Federal Republic of Nigeria, 2015). Natural gas has long been considered a by-product of oil, and many oil developers have been flaring it, resulting in substantial CO_2 emissions (Federal Republic of Nigeria, 2015). Over 130 flare sites have been identified, with the potential to fuel the generation up to 15GW of stable and reliable power – more than the country's current total installed capacity (Siemens, 2019).

It is hard to think of a country that combines challenges and opportunities on the scale seen in Nigeria. VREs are starting from an extremely low base, with great potential to grow rapidly. But Nigeria has now overtaken India as the country with the largest number of people living in extreme poverty, and must focus on what is most cost-effective and most likely to succeed in an extremely challenging context. Ending gas flaring, and reducing reliance on diesel generators, are the urgent priorities.

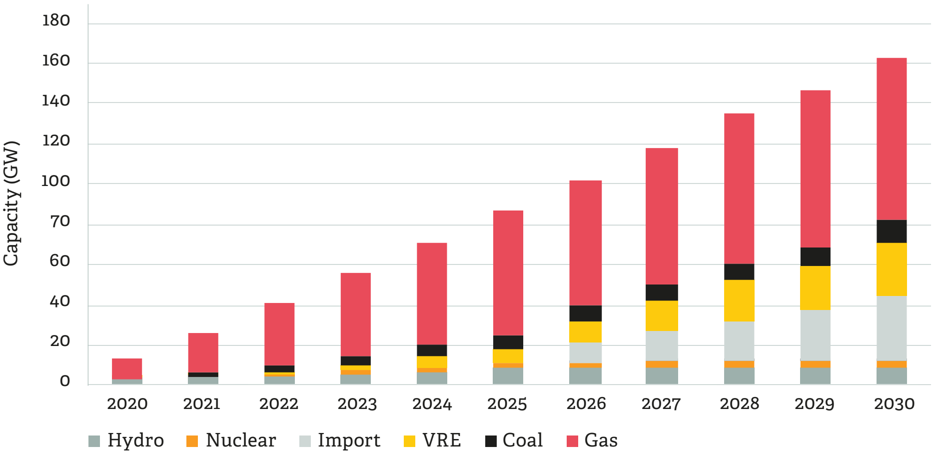


Figure 11: Nigeria 2020-2030 generation mix: 'Business as usual' (Africa Energy Portal,2019)

4.2 South Africa: Breaking the addiction to coal

 	GDP – Nominal ($ billion)	278.8
	Population (million)	58.6
	Electricity generation capacity – total (GW)	51.7
	Electricity generation capacity – renewable energy (%)	10.98%
	Electricity consumption per year – total (GWh)	227,000
	Electricity consumption per capita (kWh)	4,000

The story in South Africa is all about how quickly it can move away from coal, which generates almost 80 per cent of the country's electricity.[39] About 5,400MW, 10,500MW and 35,000MW of coal generation is expected to be decommissioned in 2022, 2030 and 2050, respectively, creating an unprecedented challenge to maintain and improve power supply.[40]

Although the country is planning a significant increase in total generation, it is not on the same scale as in other African countries, and South Africa is one of the few that can be said to be facing a 'horizontal' transition starting from a high base.

South Africa is also beset by problems. Eskom, which supplies 90 per cent of South Africa's power, is saddled with debt and loss-making. Blackouts are frequent. The politics around power in South Africa are also complicated, and the country's ageing infrastructure has suffered from under-investment for many decades.

39 IEA (2018), IEA Country Electricity Data by source.

40 DMRE (2019), Integrated Resource Plan. Department of Mineral Resources and Energy, Republic of South Africa.

South Africa is endowed with great potential for VREs. As Arndt (2019) points out, solar PV power output potential in the worst location in South Africa is greater than the best in Germany. South African wind resources are also world class and well distributed. Investment in VREs has been rapid, and South Africa's 2018 Integrated Resource Plan (IRP), expects VRE to account for 21 per cent of total electricity production by 2030. Least-cost modelling reported by Arndt suggest it could go higher than that in 2030 and hit 70 per cent by 2050. Although some studies suggest energy storage could largely supplant the load-balancing role of gas, the extent to which South Africa should use gas as a bridge between coal and VREs is hotly contested.

Decentralised solar power will also be an important part of the solution. Some of the biggest consumers of electricity are mining companies, several of which are planning their own solar parks. For example, two 200MW facilities are under development by Sibanye-Stillwater and Vedanta.[41] But despite the great promise of mini-grids to contribute to the country's transition to clean power, the regulatory environment is not as supportive as it could be.[42]

In 2018, South Africa was only generating 5 per cent of its electricity from natural gas (South Africa Energy Department, 2019). The country has introduced a gas independent power producer's procurement programme that aims to acquire an extra 3.7GW (Ting, 2019). This will bring natural gas contribution to about 10 per cent, representing a reduction in emissions in comparison to coal, and strengthen trade relations with South African Development Community (SADC) countries, such as Mozambique and Tanzania, from which liquified natural gas will be purchased (Ting, 2019). In the long term, South Africa could use its own reserves of shale gas in the semi-arid Karoo region, where there is an estimated 13 trillion cubic feet of shale gas reserves (US Energy Information Administration, 2013; Carbon Brief, 2018).

South Africa is the only country on the African continent to have a commercially operational nuclear power plant, at 1.8GW in Koeberg (Sah, et al., 2018). The latest Integrated Resources Planning (IRP) framework proposes to extend the life of Koeberg to 2044, and install an additional 1GW (500MWx2), according to the South Africa Department of Mineral Resources and Energy (2019). Another low-carbon option could be to import power from the proposed Grand Inga dam in the DRC. Others have argued for an increased role for Concentrated Solar Power (CSP) technology in the electricity mix (Pfenninger & Keirstead, 2015).

The country's energy transition has been marked by divided political and economic interests (Eberhard & Godinho, 2017). Reforms in the power sector have been turbulent since the 1998 White Paper on Energy Policy, which set out to secure energy supply through diversity by supporting renewable energy development. An unbundling plan to separate Eskom's generation, transmission and distribution operations remain stalled. Accusations of corruption are rife.

After early successes under the Renewable Energy Independent Power Producer Procurement Programme (RE IPPPP) introduced in 2011, momentum has petered out (Eberhard & Godinho, 2017; Jain, 2017). The growth of the renewable sector is seen by some as a threat to Eskom, which has refused to sign PPAs for 37 projects approved under the RE IPPPP (Baker, 2017). Emergency procurements, which were to be realised in months, have stretched into years. It is five years since the last renewable energy independent power producer auction, a powerful mechanism for identifying least-cost solutions that are often likely to include wind and solar. However, if all goes to plan, 2021 should see technology-agnostic procurement resulting in investments in wind, solar, batteries and gas.

41 Bloomberg: South Africa Miners Ready to Help Plug Part of Power Deficit.

42 ESI Africa: Loadshedding: why mini grids are the answer and why South Africa doesn't have them (yet).

The Government plans to expand generation capacity from the current 48.7GW to 73.1GW in 2030 as shown in Figure 12 (South Africa Department of Mineral Resources and Energy, 2019). Fossil fuels (mainly coal) will still play a leading role on the generation mix and is estimated to contribute up to 63 per cent of total installed capacity, with VRE sources contributing about 23 per cent.

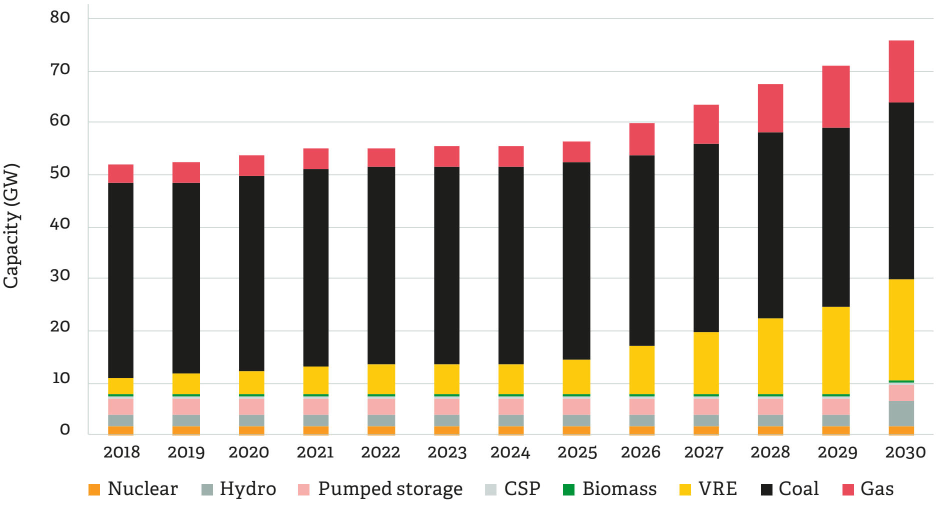
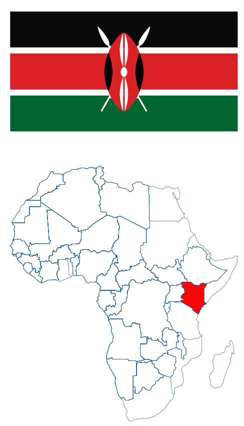


Figure 12: South Africa 2020-2030 generation mix: 'business as usual' (Integrated Resource Plan, 2019)

4.3 Kenya: Trouble in renewable energy paradise



GDP – Nominal ($ billion)	95.5
Population (million)	47.6
Electricity generation capacity – total (GW)	2.8
Electricity generation capacity – renewable energy (%)	73.8%
Electricity consumption per year – total (GWh)	8,486
Electricity consumption per capita (kWh)	178.3

Kenya has distinguished itself as a leader in renewable energy development. The 310MW Lake Turkana Wind Project is the largest wind power generator in Africa, and the country also hosts the most advance geothermal power development complex in Ol Karia, at the heart of the Rift Valley.[43] With an installed capacity of 849MW, Kenya has the largest geothermal fleet in Africa and is ranked eighth globally.

The recent integration of the 310MW of wind and 50MW of solar PV to the grid has introduced unprecedented challenges in power system operations. These additions, and others, have raised the contribution of VRE to the national installed capacity from 0.3 per cent in March 2013 to 14.6 per cent in January 2019.[44] Power system operators and planners are struggling with increased variability and uncertainty affecting their ability to balance demand and supply (GIZ and MoE, 2020). In Kenya, VRE integration is further

43 Lake Turkana Wind Power press release: (2019), H.E. President Uhuru Kenyatta officially inaugurates the 310MW Lake Turkana Wind Project.

44 Data from MoE and EPRA, public announcement made in August 2019 on a call for consultants to carry out a Power Markets Study.

constrained by the economic dispatch model employed by the utility. For instance, Lake Turkana Wind Power has a 'Take-or-Pay' PPA, which means it operates as a base load over other solid generators like geothermal when demand is low. With a national baseload of about 800MW, the fluctuating VRE component contributes up to 40 per cent, which would be challenging anywhere in the world and the difficulties are amplified by the limitations of the technologies at planners' disposal in Kenya.

Kenya has limited power systems control automation, minimal operating reserves, weak distribution and transmission network, and limited VRE forecasting capabilities. The immediate consequences include additional costs from providing support services to manage grid stability (ancillary services). More concerning is the long-term impact on geothermal resources. Since geothermal is the key source of baseload supply, the unanticipated variability during baseload periods leads to forced and sudden adjustments in power output requiring the venting of geothermal steam. Unplanned venting, resulting from poor forecasting capabilities, can degrade the performance of geothermal reservoirs.

Figure 13 shows data from October 2019, demonstrating instances of gross overestimation and underestimation of supply from a VRE source as a result of poor forecasting capabilities (GIZ and Kenya Ministry of Energy, 2019). The utility is obligated to pay for the electricity even if it is not needed, so the inability to plan for that wastes money. The quality of power supply from the utility was considered relatively low already; this situation only makes it worse.

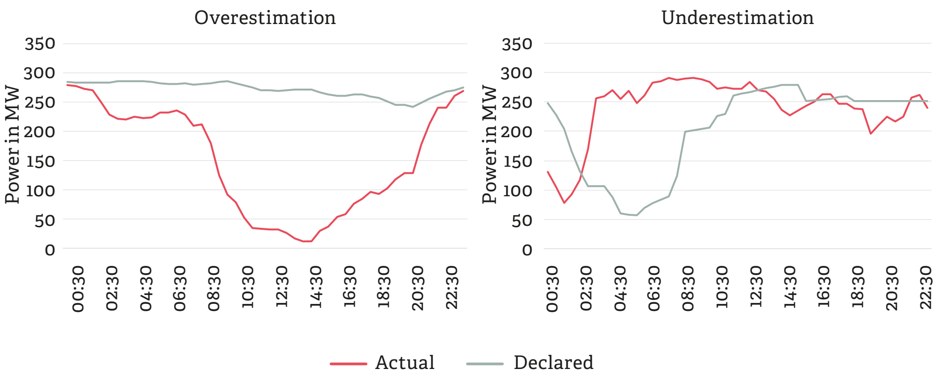


Figure 13: Limited forecasting capabilities – data collected in October 2019

The third Kenya medium-term plan (MTP III 2018-2022) which is part of the national Vision 2030, places a focus on promoting the role of renewable energy to create a climate-resilient, cost-effective electricity supply regime. In this plan, VRE sources are expected to provide more than 22 per cent of the installed capacity by 2030 (Kenya Ministry of Energy, 2018). Of this, wind power and solar PV are expected to increase to 861MW and 782MW, respectively. Based on the experience with the current fleet, there are concerns about the country's capability to handle higher shares of VRE. A recent study by the Energy and Petroleum Regulatory Authority (EPRA) estimates that the associated ancillary services to manage the current share of VRE will cost an additional $50 million per year (Mutua, 2020). This reduces the benefits that were to be realised due to the relatively low cost of the electricity from VRE. The same report also estimates the cost of curtailing geothermal and venting steam to synchronise supply translated to lost revenue of about $4 million per year for the Kenya Electricity Generating Company (KenGen).

Managing VRE now requires investments in storage capacity or liquified natural gas power generation infrastructure or pumped hydro storage – all with the aim of stabilising the dispatch of wind power to the grid. These investments necessitated by the higher VRE penetration compete with those needed to simply improve the quality of power supply distribution and expand access to electricity. The cost of connecting an additional household is around $500, so the additional $50 million in ancillary services to manage VRE equates to around 100,000 new connections, or an additional half a million people accessing electricity each year.[45]

With more than 7.5 million customers, Kenya power is now the largest electricity utility by number of connections in eastern, central and southern Africa, outside of South Africa.[46] The utility's technical and financial performance has been a source of great concern in the recent past, with technical and non-technical system losses having risen above 26 per cent (2,224GWh). During the financial year ending June 2018, was comparable to the total sales to domestic customers (2,335GWh). Government-led programmes including the Last Mile Connectivity Project (LMCP), Global Partnership in Output Based Aid (GPOBA) slum electrification project, Electrification of Primary Schools program and the on-going Kenya Off-grid Solar Access Project (KOSAP) have contributed towards doubling the number of customers over the past five years (Kenya Power and Lighting Company, 2018). Net income per customer has been falling, with total consumption growing by a mere 25 per cent after the total number of connections doubled. Compounding this problem, the utility now must contend with increasing incidences of curtailment of excess production.

Even with these challenges, the Government of Kenya, through the Ministry of Energy, aims to expand total generation capacity from the current 2.9GW to 6.5GW by 2030 (Kenya Ministry of Energy, 2017). By then geothermal, hydro, VRE sources and fossil fuels are expected to contribute about 28 per cent, 21 per cent, 24 per cent and 21 per cent of total generation capacity respectively, as shown in Figure 14.

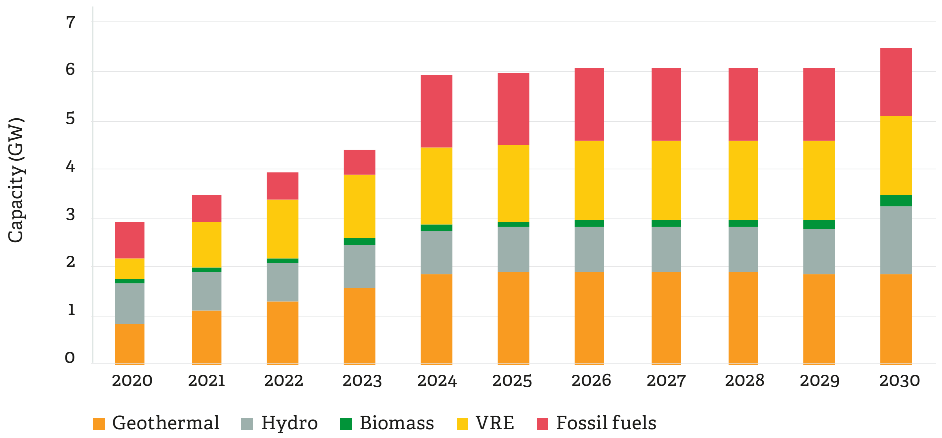
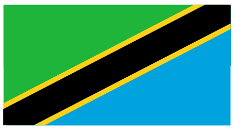


Figure 14: Kenya 2020-2030 generation mix: 'business as usual' (Kenya LCPDP, 2017-2033)

45 Phase 1 of the Kenya Power Last Mile Connectivity Project connected 314,200 at KES 13.5 billion ($13130 million13 billion) translating to about KES 43,000 per connection ($430). Source: Kenya Power (2020) Last Mile Connectivity Project

46 Kenya Power official website. Information retrieved 02/April 2020 https://www.kplc.co.ke/content/item/14/about-kenya-power

4.4 Tanzania: Setting up the silver bullet



GDP – Nominal ($ billion)	55.68
Population (million)	58.0
Electricity generation capacity – total (GW)	1.5
Electricity generation capacity – renewable energy (%)	45.2%
Electricity consumption per year – total (GWh)	7,000
Electricity consumption per capita (kWh)	100

The Stiegler's gorge in eastern Tanzania, named after a German engineer reported to have started the initial site surveys in 1901, holds the possibility of transforming the country's power sector (Baldus & Atanas, 2009). Many other studies have followed, including by the UN Food and Agriculture Organization (FAO), North American Aerospace Defense Command (NORAD), United States Agency for International Development (USAID) and the World Bank (Oestigaard, et al., 2019). For the last six decades, the power generation potential of the Stiegler gorge has been seen as the silver bullet that will revolutionalise power supply in Tanzania by providing cheap, clean and reliable electricity (Bishoge, et al., 2019).

Construction of the 2,115MW Julius Nyerere Hydropower Plant began in July 2019, and is expected to be completed by 2022. If completed successfully, the national installed capacity in Tanzania currently at 1.5GW will more than double. There are also some concerns, including a potential negative impact on the adjacent Selous Game Reserve, which is a United Nations Educational Scientific and Cultural Organization (UNESCO) heritage site; financial strain on the national energy development budget (the project is reported to have taken up close to two-thirds of the 2020-2021 Ministry of Energy allocation); excess generation capacity; and impact on the pipeline of private sector independent power producers (IPPs).[47] It is expected that some of the extra power will be exported through the African Development Bank and (AfDB) and Japan International Cooperation Agency (JICA)-funded Kenya-Tanzania 400 kV Power Interconnection project, which will connect Kenya to Tanzania, and Tanzania to the South Africa Power Pool through Zambia (African Development Bank, 2020).

The Tanzania Electric Supply Company (TANESCO) oversees the generation, transmission and distribution of electricity in this the East African Country. TANESCO also works with IPPs to fulfil its mandate. Currently, Tanzania has an installed capacity of 1.5GW, which is very low for a country with a population of 58 million people. Combined with an electricity access rate at 36 per cent, the result is per capita electricity consumption rate of just 100kWh, which is far below the 500kWh average for sub-Saharan Africa.[48] Tanzania's installed capacity is a mix of hydro, solar PV, biofuels, oil and natural gas. Hydropower and thermal energy (natural gas) make up the largest shares at 583MW and 810MW, respectively. This high dependence on hydropower makes recurring drought a major problem faced by TANESCO. Despite an abundance of solar and wind resources in the country, variable renewable energy sources account for only make up 2.5 per cent of the mix.[49] Tanzania also imports an

47 MoF (2020), Speech by the Minister of Finance and Planning, Hon. Dr. Philip Mpango, presented to the National Assembly – 2020/21, Republic of Tanzania. https://mof.go.tz/docs/THE%20UNITED%20REPUBLIC%20OF%20TANZANIA-copy%206.11.2020.pdf

48 IEA (2020), Tanzania Electricity Consumption Data and Statistics.

49 Ibid.

estimated 15MW of electricity from Kenya, Uganda and Zambia.[50] Given 63.7 per cent of the population still needs access to electricity, there have been deliberate efforts to upscale and diversify the country's electricity generation mix. These planned generation upgrades present the opportunity for the incorporation of more VREs into the mix. The 2016 discovery of additional onshore natural gas deposits is also influencing generation decisions.

The Julius Nyerere Plant should transform Tanzania's electricity sector, but changing climatic patterns are expected to increase occasional demand back-ups. Tanzania experienced a series of prolonged droughts in 2006, 2010 and 2015, the latter of which led to the complete shutdown of all hydro power plants as production dropped to lows of 20 per cent.[51] In 2014, the Ministry of Energy and Minerals developed the Electricity Supply Industry Reform Strategy and Roadmap (2014-2025) aimed at improving security of supply by not only increasing, but also diversifying, sources of electricity generation, with natural gas contributing up to 3.9GW by 2025.[52] Tanzania has proven natural gas reserves estimated at 57 trillion cubic feet with a total annual production of 110 billion cubic feet.[53] In 2007, Tanzania made the switch from imported diesel and other HFOs to locally-available natural gas. This switch saved Tanzania TZS 23 trillion ($10.6 billion) between 2004 and 2017 and cut greenhouse gas emissions.[54]

In its Power System Master Plan, the Ministry of Energy plans to expand total generation capacity from the current 1.7GW to 7.8GW by 2030, as shown in Figure 15 (Republic of Tanzania Ministry of Energy, 2020). Hydropower's contribution is expected to increase from 0.6GW to 4.2GW. It is important to evaluate how Tanzania can both capitalise on its natural gas endowments to rapidly increase the supply of reliable and affordable power, while simultaneously maximising the growth of VRE. Other countries in the continent, such as Mozambique and Angola, are in a similar position.

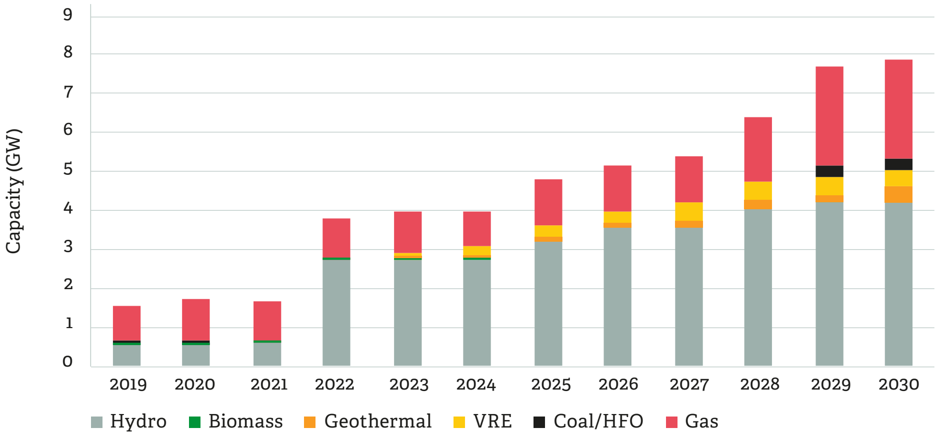


Figure 15: Tanzania 2020-2030 generation mix: 'business as usual' (Tanzania Power System Masterplan, 2020 Update)

Under its Intended Nationally Determined Contribution (INDC), Tanzania seeks to reduce its greenhouse gas emissions by between 10 per cent and 20 per cent from of its 'business as usual' scenario.[55] To meet this target, Tanzania's mitigation efforts include enhancing carbon sinks through forest conservation, afforestation, embarking on enhanced use of natural gas, and expanded use of renewable energy sources such as geothermal, solar, wind and hydro.[56]

50 IRENA (2017), Renewables Readiness Assessment: United Republic of Tanzania (pp10).

51 Hydro Review (2020), Tanzania shutting down hydroelectric plants amidst ongoing drought.

52 Ministry of Energy and Minerals (2014), Electric Supply Industry reform Strategy and Roadmap 2014-2025.

53 Tanzania Invest (2020) Gas.

54 Tanzania Petroleum Development Corporation (2018), Newsletter.

55 USAID Climatelinks (2018), Greenhouse gas emissions factsheet: Tanzania.

56 UNFCCC (2015), Intended Nationally Determined Contributions-Tanzania.

4.5 Benin: Powering economic growth

GDP – Nominal ($ billion)	14.3
Population (million)	11,801,151
Electricity generation capacity – total (GW)	0.349GW
Electricity generation capacity – renewable energy (mostly hydro) (%)	28.65 %
Electricity consumption per year – Total (GWh)	1,000
Electricity consumption per capita (kWh)	100

In September 2015, the Government of Benin and the US Government, through the Millennium Challenge Corporation, signed a $375 million agreement to support Benin's power sector.[57] Among other aims, this agreement seeks to expand generation capacity, accelerate off-grid electrification and strengthen the distribution network. Of this, at least 50MW will be powered by solar PV. Expanding private sector engagement in the electricity sector and powering economic growth is the main goal of this initiative. The *Société Béninoise d'Energie Electrique* (SBEE) is the vertically-integrated national utility in charge of generating, transmitting and distributing electricity across Benin. The SBEE fulfils this mandate through imports from the *Communaute Electrique du Benin* (CEB), a multi-national entity that supplies electricity to the national utilities in Benin and Togo. The country currently has a very low electricity generation capacity of 350MW, almost all of which is HFO, with about 1MW each from hydro and solar.[58] There are patches of off-grid solar in the form of small community mini-grids, solar home systems and residential solar. SBEE provides an estimated 12 per cent of the country's power from domestic generation, while the remaining 88 per cent is provided by CEB, largely through imported hydroelectric sources. Imports from the Akosombo dam in Ghana and the Nangbéto dam in Togo meet up to 88 per cent of electricity demand within the country.[59] The addition of 50MW from solar PV to this network will increase the share of variable renewable energy to about 14 per cent.

The power sector in Benin faces several challenges, including the financial insolvency of the SBEE, lack of a clear regulatory framework and limited participation of IPPs in electricity generation.[60] Consequently, only 42 per cent of the population has access to electricity.[61] The partnership with the MCC has appointed a private contractor to support reforms at the national utility.

57 MCC (2015), Benin power compact and the private sector – Factsheet, Millennium Challenge Corporation of the US Government.

58 USAID (2020), Benin Power Africa Fact Sheet.

59 SBEE (2020), Activities Page.

60 USAID (2018), Benin Power Africa Power Sheet.

61 ESMAP (2019), Tracking SDG7: Benin.

Supply problems with imported power from Ghana and Ivory Coast in 2007 and 2008 encouraged the country to focus on increasing its own generation capacity.[62] In 2019, Benin inaugurated the Maria Gléta 127MW dual HFO and gas power plant near the port of Cotonou.[63] The plant sets Benin on a path towards energy independence, with plans to expand the power plant to 400MW.[64] In its first Nationally Determined Contribution (NDC) report, Benin plans to move the fuel mix towards natural gas, with 500MW by 2030.[65] Benin is reported to have approximately 35.3 billion cubic feet of proven natural gas reserves, although presently all fuel used in the country is imported.

Benin is an example of a low-income sub-Saharan country that is heavily reliant on imported power. Understanding how countries that are lacking natural fossil fuels but with huge untapped wind and solar potential can manage the transition is a necessary addition to the decarbonisation discourse.

Benin's transition to a fully renewable grid would essentially require building out a completely new generation infrastructure. There is hydro potential of 760MW along River Oueme, but this has not been fully developed.[66] Plans are underway to develop the Adjaralla hydropower plant on the Mono river which serves as the border between Togo and Benin. The dam has been a source of conflict between the two countries for over a decade.[67] Existing projections to 2030 foresee a greater role for hydropower, but with fossil fuel continuing to play the main role in domestic generation as shown in Figure 16. On paper there is certainly potential to expand VREs more rapidly, with the Maria Gléta plant there to provide support, but the country is starting from a low base with a weak national utility.

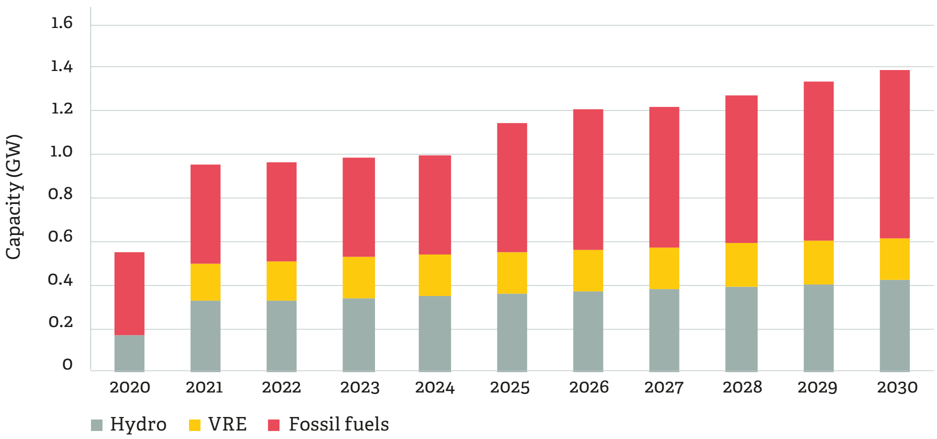


Figure 16: Benin 2020-2030 generation mix: 'business as usual' (USAID, Power Africa Transactions and Reforms Program)

62 Energypedia (2015), Benin Energy Situation.

63 Africa Oil and Power (2019), Benin inaugurates 127MW power plant.

64 Africa Oil and Power (2019), Benin inaugurates 127MW power plant.

65 Benin Republic (2015), Benin's first nationally determined contribution under Paris Agreement.

66 REEEP (2012) Benin.

67 The Discourse (2017), Togo and Benin pin energy hopes on this controversial dam.

4.6 Senegal: Greening the grid

GDP – Nominal ($ billion)	23.6[68]
Population (million)	16.3
Electricity generation capacity – total (GW)	1.2[69]
Electricity generation capacity – renewable energy (%)	18.7%[70]
Electricity consumption per year – total (GWh)	3,329
Electricity consumption per capita (kWh)	204.2

Senegal is the star in our pack. It is investing heavily in new solar and wind generation, complemented by batteries and responsive gas generation, rapidly expanding supply and improving reliability. The iconic Taiba N'Diaye wind power plant in the north-west part of Senegal was scheduled to be commissioned by the end of 2020 and, at 158.7MW, will be the largest wind project in west Africa. Today, about 86 per cent of Senegal's installed capacity is from fossil fuels, mainly diesel.

Senegal's power supply sector has come a long way since 2011, doubling its capacity from 500MW to 1,141MW and lowering the cumulative total hours of power cuts from 950 hours to 24 hours in 2018.[71] Solar PV now contributes more than 10 per cent of the total in-country installed capacity and additional capacity is under development.[72] Sarr, et al., (2018) estimate that the maximum penetration rate for solar PV under the current technical circumstances is around 17 per cent. Combined with wind generation, this is expected to create new and unprecedented power system management challenges.

Senegal's ability to invest in renewables, storage and new gas generation to complement them, has been helped by the commercial turnaround of the state-owned utility, which had previously been making losses. It posted $52 million in profits in 2016, and had a successful initial public offering in 2018. The management of the electricity sector in Senegal was partially unbundled in the late 1990s allowing private participation in generation.[73] The part-privatised national utility Senelec still has the monopoly on transmission and distribution, and owns almost half the generation capacity.[74]

Senelec is reported to be in the process of procuring an 80MWh battery storage solution to help mitigate some of the anticipate variability from increased shares of VRE. That investment will include the need for Balance of System (BOS) equipment, like inverters and smart controls, to optimise the charging and discharging cycles. Further investments in BESS could be helped by opening other revenues streams (such as from ancillary services and price arbitrage) that battery investors rely on in advanced economies, and which are not yet available in Senegal.

68 World Bank (2020), Senegal country data.

69 Senelec (2018), Rapport Annuel 2018.

70 IRENA (2019), Renewable Energy Statistics 2019.

71 Africa Oil & Power (2019), Senegal to boost electricity production.

72 Senelec (2020), List of generation plants.

73 REEEP (2014), Senegal.

74 REEEP (2014), Senegal.

Heavy investment in VREs was a response to high dependency on imported oil, exposing the country to international fluctuations in price. The Government of Senegal now aims to make the energy sector self-sufficient. Senegal is among the African countries that have recently discovered natural gas (World Bank, 2019). The Grand Tortue Ahmeyim (GTA) gas field that straddles across Mauritania and Senegal are set to lower the electricity sector's greenhouse gas footprint by displacing coal.[75] The 300MW Cap des Biches gas plant is expected to begin operation next year, with capacity equal to roughly a quarter of the power currently consumed in the country, and is intended to support more rapid investments in renewables as well as replacing dirtier coal generation. In its Nationally Determined Contribution (NDC) submission to the UNFCCC under the Paris Agreement, Senegal aims to replace the Jindal 320MW coal-fired power plant with gas (Republic of Senegal, 2015).

Senegal has not exploited hydroelectricity despite having an estimated potential of around 1.4GW along the Senegal and Gambia rivers.[76] Development of this resource which extends transnational boundaries will require extensive diplomatic collaboration. Discussions for the shared use of the Gambia river started in 1980s, and only in 2019 was a joint OMVG energy project that includes construction of the Sambangalou hydropower station finalised.[77]

Senegal has 272 mini-grids, the largest number of mini-grids per country on the African continent, and is reported to have a pipeline of 1,217 mini-grids to be developed (World Bank, 2019). With the IEA estimating that 54 per cent of Africans who currently lack access would be best served using decentralised approaches (IEA, 2017), Senegal is leading the way in this approach.

Under electricity sector reform *Plan Directeur De Production et De Transport D'électricité Du Sénégal 2017-2035*, Senegal aims to attain universal access by 2025. It plans to increase its economic competitiveness through supply of reliable and affordable power, and reduce negative environmental impacts by promoting cleaner energy technologies. Under a partnership with the USAID Power Africa initiative, the country expects to almost double its generation capacity by 2030 and achieve 30 per cent penetration of VREs (mainly solar PV) by 2030, with support from the World Bank. After growth in hydro, gas will contribute the bulk of the country's power, with investment in short-term gas generation to enable higher shares of VRE.

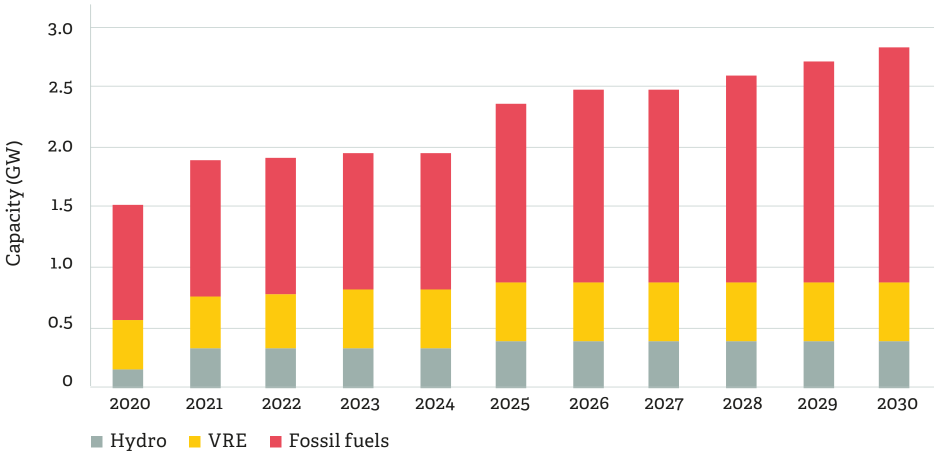


Figure 17: Senegal 2020-2030 generation mix: 'business as usual' (Power Africa Transactions and Reforms Program).

75 BP (2020), The Grand Tortue Ahmeyim Project

76 Get.invest Senegal Renewable Energy Potential

77 https://www.gauff.net/en/references/senegal/omvg-hydroelectric-power.html and AfDB (2019), Multinational OMVG Energy Project – Summary FRP.

05

Accelerating decarbonisation in Africa

Those wishing to accelerate the pace of decarbonisation in Africa have work to do on many fronts. This section summaries the opportunities and priorities.

An overarching concern is the lack of competition. State-owned utilities that build and operate their own infrastructure can be innovators too, but with so many possibilities (both in the choice of technology and mode of operation) and so much to learn, there is a strong case for harnessing the power of competition between private firms. About ten countries in Africa have vertically unbundled utilities and only 25 permit private sector participation in the power sector.[78] As witnessed in the rapid technology-driven inclusion of Africa's unbanked population through digital innovation, market liberalisation and an enabling regulatory environment saw rapid progress in Kenya, while the lack dulled growth in neighbouring Ethiopia. The same will likely be true for the rapid expansion of the technologies needed to decarbonise Africa's electricity grid.

Another overarching consideration is, of course, finance. Carbon emissions are a textbook example of a negative 'externality' that will not factor into investment decisions unless steps are taken to internalise global environmental costs. But there are also positive externalities from experimentation and learning with novel low carbon technologies, and potential economies of scale in equipment manufacturing. There is, therefore, a case for subsidising early investments in energy storage and other innovations to learn and demonstrate what works, rather than relying on commercial actors to make investments only once there is an expectation of profit. African governments will have limited appetite for subsidising decarbonisation out of their own fiscal resources. The World Bank's $1 billion Accelerating Energy Storage for Development programme, and its Energy Storage Partnership, is an example of support from the international community.

78 The Development Bank of Southern Africa (2019), Briefing note: Unbundling practices and opportunities for private sector engagement in energy transmission in Africa. https://www.dbsa.org/EN/About-Us/Publications/Documents/Briefing%20note%20Unbundling%20in%20the%20Energy%20Sector%20in%20Africa%20-%20July%202019.pdf

Reducing the prices of wind and solar would be helpful, but as this report has explained, once VRE penetration reaches a certain level, other considerations become more important. This suggests that subsidies might be targeted at changing the price of complementary investments that will relax the constraints on high VRE penetration.

5.1 Transmission and distribution

The dilapidated state of the grid infrastructure in many African countries imply that the priority is to put the rudimentary functions of a power system in place. To rapidly scale VRE, management of weak and disjointed power systems across most regions will need to be dramatically strengthened. This will include: accurate weather and plant power forecasting; enhancing capacity to conduct sub-hourly dispatch and intra-hourly scheduling; deployment of Automatic Generation Control (AGC); and introducing VRE tracking options (including gas).

5.2 Time-varying tariffs

State-owned utilities can incorporate storage into their power networks as they wish, but private providers will not do so without a business model. The key to profitable investments in storage is varying charges and payments for power at different times of the day, or power purchase agreements that specify levels of service when demanded that bidders find most cost-effective to meet by investments in BESS.

With the recent and continued fall in grid-scale battery storage costs, time-varying payments create the potential for a profitable business model from standalone battery storage. A profit can be made by charging when power is cheap and selling it back to the utility when prices are high, or by charging cheap and then using the power to manage frequency and voltage deviations in return for payments from the utility.

Time-varying charges and payments to battery operators can be complemented by time-of-use (ToU) tariffs on the demand side, to encourage large users to shift their power consumption to when VRE is available. ToU tariffs would require advanced metering infrastructure and more sophisticated systems that can achieve real-time adjustment of pricing based on supply and demand. ToU tariffs are widely used in Europe and North America, but only half of sub-Saharan countries have implemented this pricing policy and to varying degrees (Kojima & Han, 2017).

To create new business models that will accelerate the adoption of VRE in combination with storage, IRENA calls for innovations along three dimensions:[79]

	Innovation dimension	Example of innovation	Investment required
1	**Business models:** innovative models that create a business case for new services enhancing system flexibility.	• Peer-to-peer electricity trading • Aggregators • Electricity-as-a-service • Pay-as-you-go (PAYG)	**Moderate** • Possible regulatory changes • Private sector participation in energy sector
2	**Market design:** new market structures and regulations to stimulate new business opportunities.	• Net billing schemes • Innovative ancillary services • Demand side	**Low** • Possible regulatory changes • Change of roles of key actors in power sector
3	**System operation:** new operation procedures that enhance electricity system flexibility.	• Advanced forecasting for VRE generation • Virtual power lines • Dynamic line rating	**Moderate** • Possible regulatory changes • Capacity development and training of personnel

Table 4. Inexhaustive summary of innovation dimensions (adopted from IRENA)

79 IRENA (2019), Innovation landscape for a renewable-powered future: Solutions to integrate variable renewables.

5.3 Interconnectors and regional power pools

As a continent, Africa has one of the highest VRE potentials in the world, but there are important regional variations that call for investments in interconnectors and well-managed regional power pools. The hydropower potential in Ethiopia, Tanzania, and DRC, coupled with geothermal in Kenya, Rwanda and Tanzania, could play a critical role by providing low-carbon sources of firm power to complement VREs, but will need extensive evacuation corridors to reach other parts of the continent. Without these, enormous hydropower investments, such as the Grand Inga III, will fail.

Several initiatives are in process but must be accelerated. In East Africa, the AfDB and JICA are supporting the construction of a 507km high-voltage transmission line connecting Kenya and Tanzania. This will be part of the Eastern Africa Electricity Highway, with a transfer capacity of 2,000MW, and will be the major link for power transfer between the EAPP and Ethiopia, Sudan and Egypt.[80] Investments on this scale are needed across the continent.

The need to manage national hostilities, divergent geopolitical interests, varying energy prices, uncoordinated grid codes, different policy regimes and attitudes towards to private sector investment, and other challenges, affect the viability of regional power pools. The Southern Africa Power Pool (SAPP) is the most advanced, where 12 are national utilities and five private companies can trade power. It has demonstrated the value of markets that offer members more flexibility to response to events.[81] It has a strong supervisory body to ensure fairness and adherence to rules.[82] In 2017, SAPP completed its 2040 Pool Plan to guide generation and transmission investments of regional significance. The Plan also helps investors make informed decisions that are in alignment with the priorities of the region. Integration is projected to save the region about $42 billion over a period of 25 years, compared to countries acting in isolation.

80 AfDB (2020), Multinational Kenya-Tanzania Power Interconnection Project.

81 SAPP (2019), Annual report, 2019.

82 SAPP (2020), Market Surveillance.

06

Conclusion

The challenge of achieving high shares of VRE in Africa is fundamentally different from that in wealthier economies with mature energy infrastructure and relatively flat demand. African countries need not be so reliant on centralised grids as earlier developers, but a severalfold increase in power delivered over the grid will be necessary for them to meet their urgent economic development objectives.

African countries have joined the global effort to transition to net zero by mid-century, and with ample renewable resources they can leapfrog the highly carbon-intensive path followed by earlier developers. Decentralised mini-grids can also overcome many of the problems that hold back grid expansion. But it is not possible to leapfrog immediately to 100 per cent renewables generation on the grid.

Rapid and sustained investment in wind, solar and batteries will set Africa on a path to net zero by 2050, which will also require major investments in national and international transmission infrastructure and network management technologies. Some investments in the 'firm' sources of power that wealthy countries all currently rely on will also be required. In countries without access to large hydropower or geothermal resources, that implies some selective and time-bound investments in gas power. The pace of grid decarbonisation will depend not only on how quickly energy storage costs fall, but also on how quickly supportive regulations – and more sophisticated operating capacities – are in place, so that African utilities can integrate storage onto their networks as soon as possible. The time when new investments in gas generation are no longer needed is fast approaching, and there is much that governments, private investors and international organisations could be doing to bring it forward.

African countries stand no chance of meeting the SDGs, of lifting their people out of poverty and achieving a decent standard living for all, without affordable, reliable and sustainable electricity. African governments face huge demands on their limited fiscal resources and cannot be expected to deviate from least-cost technical solutions when taking power network investment decisions. African countries should, therefore, be supported in their efforts to achieve their self-determined, least-cost power sector development plans and future long-term decarbonisation plans under the Paris Agreement.

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