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Planning and prospects for renewable power: EASTERN AND SOUTHERN AFRICA

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The International Renewable Energy Agency (IRENA) serves as the principal platform for international co-operation, a centre of excellence, a repository of policy, technology, resource and financial knowledge, and a driver of action on the ground to advance the transformation of the global energy system. An intergovernmental organisation established in 2011, IRENA promotes the widespread adoption and sustainable use of all forms of renewable energy, including bioenergy, geothermal, hydropower, ocean, solar and wind energy, in the pursuit of sustainable development, energy access, energy security and low-carbon economic growth and prosperity.

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FOREWORD

The countries of Eastern and Southern Africa stand at a crossroads.

To meet the needs of their growing economies significant installations of new, cost effective power generation capacity are required. Indeed, electricity demand is forecast to grow by 5% and 3.4% per year in the two regions respectively to 2040.

However, meeting these needs requires in depth analysis and the establishment of well informed, farsighted energy plans that harmonise immediate economic objectives with the long-term benefits presented by sustainable energy.

Francesco La Camera
Director-General,
International Renewable Energy Agency

Renewables are uniquely placed to meet the region's thirst for new electricity. This report finds the region could cost-effectively meet 63% of its electricity needs with renewables by 2040, around three times today's levels. Half of which could come from solar and onshore wind.

The flexibility required to accommodate high shares of renewables can be achieved through continued investment in cross-border transmission infrastructure and a deepening of electricity trade. This allows for a more diversified generation structure and builds resilience into the continent's power system.

Despite this potential, fossil-fuels still dominate long-term energy plans, which currently include 100 gigawatts of new coal by 2040. This path threatens to lock in unsustainable energy investments and expose regional economies to the destabilising effects of stranded assets in the future.

I am confident this analysis provides useful inputs to the process of regional and continental infrastructure planning, such as the Programme for Infrastructure Development in Africa (PIDA) and the Continental Transmission Masterplan.

A low-carbon energy pathway has the potential to do more than just meet the region's growing energy needs. It promises to fuel an unparalleled age of inclusive, sustainable growth well into the 21st century. To realise this future, it is critical that long-term planning decisions made today, enable it.

CONTENTS

CONTENTS

CONTENTS

FIGURES

FIGURES

TABLES

BOXES

ABBREVIATIONS AND ACRONYMS

ACEC	Africa Clean Energy Corridor
AUC	African Union Commission
AUDA-NEPAD	African Union Development Agency – New Partnership for Africa's Development
BAU	business-as-usual
CAPEX	capital expenditure
CCGT	combined cycle gas turbine
CSIR	Council for Scientific and Industrial Research
CSP	concentrated solar power
DNI	direct normal irradiance
DRC	Democratic Republic of the Congo
EAPP	Eastern African Power Pool
EDF	Électricité de France
EU	European Union
FOM	fixed operation and maintenance
GDP	gross domestic product
GEIDCO	Global Energy Interconnection Development and Cooperation Organization
GHG	greenhouse gas
GJ	gigajoule
GW	gigawatt
HFO	heavy fuel oil
HVDC	high voltage direct current
HVAC	high voltage alternating current
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IFC	International Finance Corporation
IIASA	International Institute for Applied Systems Analysis
INDC	Intended Nationally Determined Contribution
IPP	independent power producer
IRENA	International Renewable Energy Agency
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelised cost of electricity
LNG	liquid natural gas
MESSAGE	Model for Energy Supply System Alternatives and their General Environmental Impacts
MIT	Massachusetts Institute of Technology
MW	megawatt
NDC	Nationally Determined Contribution
OCGT	open cycle gas turbine
PAP (I and II)	(PIDA) Priority Action Plan
PIDA	Programme for Infrastructure Development in Africa
PPIAF	Public–Private Infrastructure Advisory Facility
PV	photovoltaic
RE	renewable energy
REF	Reference scenario
REM	Reference Electrification Model
ROR	run-of-river
RSA	Republic of South Africa
SAPP	Southern African Power Pool
SAST	South African Standard Time
SPLAT	(IRENA) System Planning Test
TAF	(EU) Technical Assistance Facility
TW	terawatt
UETCL	Uganda Electricity Transmission Company Limited
UNDP	United Nations Development Programme
UNECA	United Nations Economic Commission for Africa
UNSD	United Nations Statistics Division
USD	United States dollar
UTC	Coordinated Universal Time
VOM	variable operation and maintenance
VRE	variable renewable energy

EXECUTIVE SUMMARY

East and Southern African countries possess vast potential for renewable energy development. In the crucial years ahead, co-ordinated regional plans will play a vital role in scaling up the use of renewables for power generation, strengthening regional power supplies, meeting national climate commitments and ensuring energy security.

The International Renewable Energy Agency (IRENA) supports countries across East and Southern Africa in their endeavour to establish a regional transmission corridor for sustainable electricity, based specifically on renewable sources and technologies. IRENA's Africa Clean Energy Corridor (ACEC) framework envisages a broad, North–South power transmission chain that encompasses 21 continental countries in the East African Power Pool (EAPP) and Southern African Power Pool (SAPP). The ACEC initiative, endorsed by Ministerial Communiqué in January 2014 during the Fourth IRENA Assembly, continues to guide regional co-ordination on renewable power development, energy sustainability and cross-border electricity trade.[1]

This report assesses the prospects for the power sector in the countries of the ACEC through 2040. As well as analysing the master plans of the two key power pools, it highlights sustainable, renewables-based alternatives based on IRENA's latest dataset. The analysis supersedes earlier studies in the *Planning and prospects for renewable energy* series.

IRENA's power sector planning tool, the System Planning Test (SPLAT) model, is applied to the two regional power pools, including their plans and prospects for capacity expansion. This quantitative model highlights each country's least-cost supply options to 2040, taking operational constraints and resource potential into account.

With the capital costs for renewable-based power-generating technologies continuing to fall significantly, countries in the EAPP and SAPP have added roughly 40 gigawatts (GW) of new renewable power capacity since the last assessment in 2015. Subsequent analyses have combined the two power pools into a single SPLAT-ACEC model and incorporated these recent developments.

1 The Africa Clean Energy Corridor spans 21 continental countries in the SAPP and EAPP, namely Angola, Botswana, Burundi, Democratic Republic of the Congo, Djibouti, Egypt, Ethiopia, Eswatini, Kenya, Lesotho, Libya, Malawi, Mozambique, Namibia, Rwanda, South Africa, Sudan, Uganda, United Republic of Tanzania, Zambia and Zimbabwe. IRENA's analysis also includes South Sudan, but not Libya. For simplicity, the "ACEC region" in this report refers to 21 countries, including South Sudan and excluding Libya.

Variable renewable energy (VRE) – namely onshore wind and solar photovoltaic (PV) power – presents specific planning and modelling challenges. Instead of assigning generic capacity factors to VRE sources, the updated model includes hourly generation profiles for key solar and wind zones in each country. Time-slice calibration is improved to better capture the potential alignment of VRE supply with variable demand, as well as time-linked operational constraints (e.g. flexibility) and other aspects of the power system.

IRENA has conducted an in-depth analysis of the assumptions and results of the EAPP and SAPP master plans. Consequently, the Agency has produced a series of achievable long-term regional electricity generation and transmission goals to guide future system expansions, and highlighted transboundary infrastructure projects that could help to create an integrated regional market.

The analysis of the master plans has also refined existing data on demand, cost, resource potential and investment options. Through a zoning analysis, high-potential locations were screened as candidate sites for VRE development and deployment. Results from the SPLAT-ACEC model on wind and solar penetration, trade and hydropower, under six different scenarios, have revealed possible development options for power generation and cross-border trade as demand triples by 2040.

The analyses conducted for each of these scenarios are translated into targeted recommendations for potential generation and transmission projects of regional importance. The findings may serve as inputs to regional and continental infrastructure planning processes, such as the Programme for Infrastructure Development in Africa (PIDA) and the Continental Transmission/Power Systems Masterplan.

This report presents the following main findings:

- **The long-term outlooks of existing master plans envisage a tripling of sent-out demand across ACEC countries to 1 600 terawatt hours (TWh) by 2040.** The deficit between projected peak demand (263 GW) and existing and committed capacity would amount to about 115 GW by 2040. To meet this gap, even in the renewable-friendly scenarios of the master plans, solar PV and wind only feature modestly in the 2040 capacity mix – at 24% in the SAPP and 34% in the EAPP. According to IRENA analysis, up to 230 GW of solar PV and wind – representing a combined share of 50% in the capacity mix – is possible across the region by 2040.

- **Unless generation capabilities are reviewed and re-imagined, the ACEC region is on track to construct more than 100 GW of new coal-fired power based on existing power pool master plans from 2020 to 2040, thereby tripling carbon dioxide (CO_2) emissions to 1 200 megatonnes (MT) per year.** In contrast, this report offers a way forward based on realistic options to ensure a high level of solar PV and wind penetration through affordable, low-cost investments. The region's existing stock of coal-fired generation capacity (approximately 50 GW) could be scaled down through plant retirements to 35 GW by 2040, assuming new solar PV and wind projects are preferred over the construction of new coal plants.

- **The ACEC region is well endowed with wind and solar resources.** Not only are these resources of high quality; they are also regionally well-distributed. Of the 7 000 GW and 2 000 GW, respectively, of solar PV and wind potential identified, less than 1% is currently exploited. IRENA examined the economic potential of 335 zones (285 GW) in detail using the SPLAT-ACEC model.

- **Solar and wind power must be deployed at a large scale to ensure the cost-effectiveness of the regional power system.** Under this report's Reference scenario (based on current plans and policies), power generation from solar PV and onshore wind looks set to reach 36% of total generation by 2040, up from 2% in 2016. Wind would reach 98 GW and solar 134 GW. Alongside other dispatchable renewable energy technologies (especially hydropower), the total share of electricity generation from renewables could grow from 20% in 2016 to 63% by 2040.

- **Emissions from the power sector would peak mid-decade and thereafter decline to below 2020 levels by 2040 in most of IRENA's scenarios.** Annual emissions in 2040 could be reduced to between 26% and 35% of the levels projected in the master plans (lower by 730 MT) in their base case scenarios. If VRE deployment is lowered to a 20% share in electricity generation by 2040 (e.g. by capping deployment to an upper bound, subsidising fossil fuels or preventing market forces from influencing technology choice), total system costs will be USD 22 billion (approximately 1%) higher, while annual CO_2 emissions from electricity generation will be 15% higher. The system cost does not include the costs of strengthening distribution networks or flexibility (i.e. no balancing market or ramping costs are considered).

- **Synergies between hydropower and VRE sources can help to make the overall electricity system more flexible, both nationally and regionally.** Wind power offers strong synergies with hydropower across the region, while solar PV has emerged as a key complementary technology. In Angola, Ethiopia, Namibia and Zambia, for example, solar PV generation during the day is complemented by hydropower generation at night.

- **Interconnector infrastructure expansions can facilitate power trade between ACEC countries endowed with different types of renewable energy resources.** For example, hydropower generation profiles in the Democratic Republic of the Congo (DRC) and solar PV generation profiles in South Africa are shown to be highly complementary.

- **A diverse mix of renewable sources can offset temporary or seasonal shortfalls in hydropower.** When hydropower production is reduced due to low hydrology or delayed projects, solar PV and wind power generation can be used to fill the supply gap. The supply mix can also be diversified by including 20 GW of additional biomass.

- **The regional power system would benefit from increased cross-border electricity trade, partly as a balancing mechanism against supply fluctuations for solar PV and wind power.** Trade volumes for power would increase by 4.5 times in the ACEC region between 2020 and 2040, while 143 GW of new capacity additions would be expected. Beyond the interconnector capacities that are already committed, the potential exists for a further 15 GW of capacity additions by 2040. The number of country pairs with interconnectors could almost double, from 18 to 35 across the region.

- **Creating a renewable-powered system for the entire region entails costs of USD 2 trillion (in 2015 USD) over 20 years (cost of capacity, fuel and O&M between 2020 and 2040).** Of this, some USD 960 billion relates to committed projects. The cumulative investment for power generation projects would amount to USD 560 billion. Approximately USD 8 billion would be needed for interconnector expansions. These figures are derived from a cost minimisation model and would be subject to changes in assumptions; they serve to indicate the order of magnitude of investment requirements.

- Examples of nine high potential solar and wind zones for development are identified based on their robustness, projected generation and contribution to security of supply. Six interconnection projects are featured for the opportunities they present for regional integration.

The analysis presented here is based on publicly available information, including the EAPP and SAPP master plans, as well as inputs from national representatives. Assumptions regarding fuel costs, infrastructure and policy developments may be viewed differently by various stakeholders in the region. As the data and analysis are continually improved, updated and expanded, validation by local experts will serve to enhance the robustness of model results.

Rather than forecasting the future, the model seeks to explore different possibilities and their potential implications. All scenario outcomes result from decisions based on assumed cost developments for fuels and technologies. Local, regional and continental experts should continue to explore different assumptions and provide alternative scenarios.

Developing and comparing all scenarios will help to build a clearer picture of the benefits and challenges of the widespread, accelerated deployment of renewables across East and Southern Africa.

Wind turbines in flowering fields in spring, South Africa
© Shutterstock

INTRODUCTION

Southern and Eastern Africa are endowed with extensive untapped renewable resources. With rapidly declining costs and increasing policy support, solar PV and onshore wind generation technologies have, in recent years, established strong business cases and begun taking off at scale in selected African markets, such as in South Africa and Egypt. The International Finance Corporation (IFC) has been helping to scale up the use of solar technologies in smaller African countries (IFC, 2020). However, despite their massive potentials, renewables are yet to be fully reflected in national and regional plans and strategies. Under current regional master plans, fossil fuels will be relied upon heavily to meet the increasing electricity demand.

Nevertheless, investors are becoming increasingly cautious given the environmental, financial and social risks associated with fossil fuel investments. Despite the availability of domestic fossil energy resources – such as natural gas in Mozambique and United Republic of Tanzania (Tanzania); and coal in Botswana, Mozambique, South Africa, Tanzania and Zimbabwe – many governments are looking for ways to expand affordable renewable portfolios in their national and regional energy master plans. At the continental level, there is also similar interest. While maps of the renewable resource potentials of the sub-continent are becoming more widely available, the areas with the most potential for project development have yet to be developed into concrete renewable sites or reflected as viable investment options in energy plans.

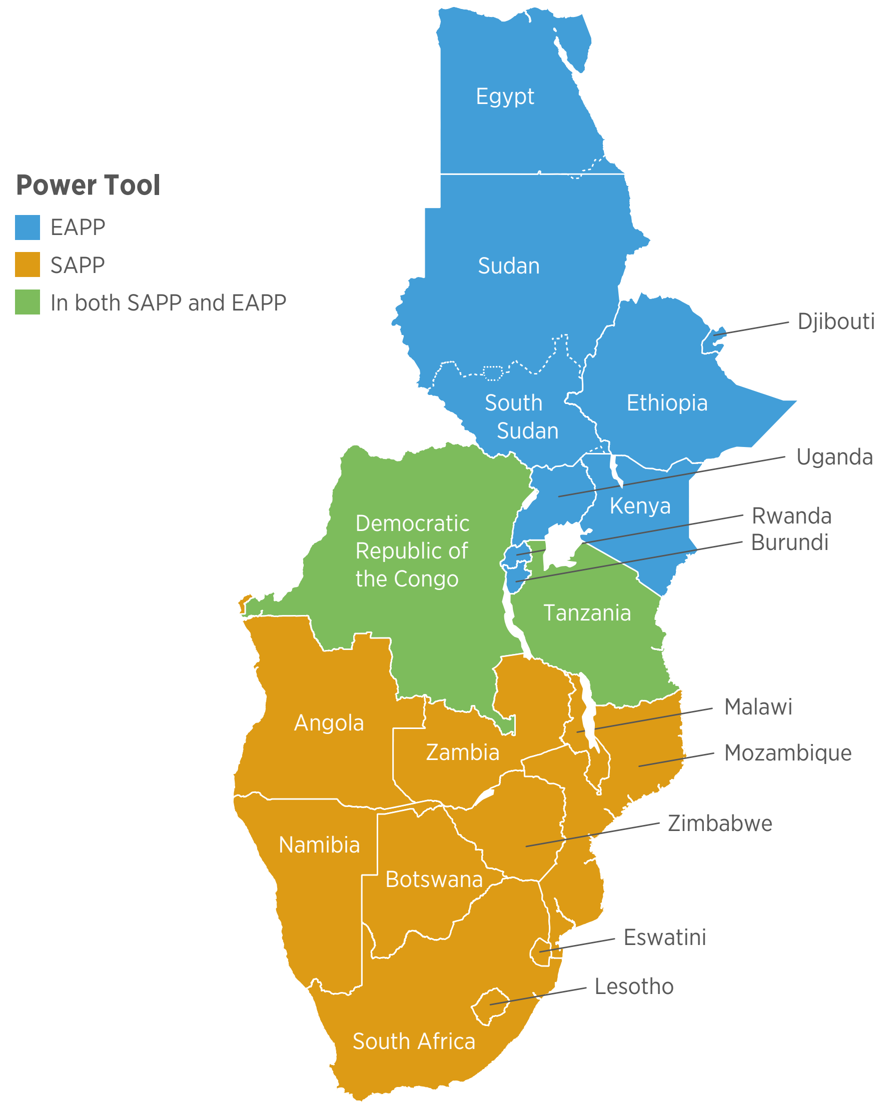
In order to assist countries in this regard, this report illustrates how such investment options may be identified from renewable potential. It also discusses how these investment options can diversify the electricity supply mix and discusses a regionally coordinated approach through regional power pools. While this report considers grid-connected power generation, with growing energy access through mini-grids and stand-alone systems, distributed generation is also foreseen for future integration to the national grid.

IRENA supports the work of power pools in Africa through the analysis of renewable power prospects and planning requirements, and of proposed transboundary transmission capacity expansions; such analysis also provides input on regional coordination and the planning of power pools (e.g. updates of power pool master plans). The concept of 'clean energy corridors' in Africa – including the African Clean Energy Corridor (ACEC) – was adopted at the meetings of the Specialized Technical Committee on Transport, Transcontinental and Interregional Infrastructure, Energy and Tourism held in Lomé in 2017 and Cairo in 2019. It therefore featured in the 2017–19 and 2020–21 action plans of the African Union.

In the framework of the ACEC, endorsed by heads of state, IRENA supports the Southern African Power Pool (SAPP) and the East African Power Pool (EAPP), including the vision of fostering a North–South power transmission corridor. The ACEC comprises 21 continental countries in the SAPP and EAPP, namely Angola, Botswana, Burundi, the Democratic Republic of the Congo (DRC), Djibouti, Egypt, Ethiopia, Eswatini, Kenya, Lesotho, Libya, Malawi, Mozambique, Namibia, Rwanda, South Africa, Sudan, Uganda, United Republic of Tanzania (Tanzania), Zambia and Zimbabwe. IRENA's analysis also included South Sudan, but not Libya. For simplicity, the "ACEC region" is used in this report to refer to these 21 countries, including South Sudan and excluding Libya.

The report assesses the investment potentials of renewables to the year 2040, focusing on solar PV and onshore wind. Ten years after the NDC target year, 2040 is also the modelling horizon of the power pools' master plans.

Figure 0-1: Countries included in the ACEC region.



Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

The report's analysis uses a generation and transmission capacity expansion model developed by IRENA, combined with a detailed zoning analysis that IRENA developed with the Lawrence Berkeley National Laboratory (LBNL) in 2015. Within this analytical framework, IRENA assessed the economic viability of generation project sites in the context of overall long-term power system development needs at both the country and multi-country levels. Various investment risk factors are addressed, including the impact of climate change (i.e., limited water availability for hydro storage and power generation) as well as lack of progress in the development pipeline of interconnectors.

These analyses are translated into targeted recommendations for potential generation and transmission projects of regional importance. The findings may serve as inputs to regional and continental infrastructure planning processes, including the Continental Power Systems Masterplan[2] and Programme for Infrastructure Development in Africa Priority Action Plan 2 (PIDA – PAP 2)[3] (PIDA, 2018; 2017). The PIDA vision for renewable energy recognises the vast renewables potential in the region.

The report is structured into three parts. Part I of the report provides the background to the ACEC region's power system and assesses its overall renewables resource potential. Part II of the report discusses the long-term outlook for power systems in the region and investment potentials in renewable power generation. Part III gives some examples of high potential areas for the deployment of variable renewable energy generation technologies, as well as notable infrastructure investment projects for the PIDA processes.

2 *AUDA-NEPAD is leading the establishment of a Continental Transmission Network to link all African utilities. The network power network will include both generation and transmission, also connecting to Europe and Asia. A master plan for the network is currently under development.*

3 *The PIDA is a strategic framework covering the period to 2040, with the buy-in of all African countries to develop continental-scale infrastructure projects – including energy infrastructure – and to strengthen the consensus and ownership around those projects.*

PART I:

MOTIVATION AND RENEWABLES POTENTIAL

Part I offers a background picture of the regional power systems and renewable resource potential for the subsequent analysis.

Chapter 1 (Current status and recent developments) presents an overview of the current status of the regional power system.

Chapter 2 (Outlook from EAPP and SAPP master plans) provides an outlook based on the regional master plans.

Chapter 3 (Renewable resource potential in the ACEC countries) describes the method employed in this report to define potential solar PV and onshore wind project zones for modelling. Other renewable sources are also briefly discussed. The zones and their attributes are then used for modelling in Part Two.

CURRENT STATUS AND RECENT DEVELOPMENTS

1

This chapter provides an overview of the power systems of the ACEC countries, in terms of current electricity production, generation capacity and capacity of transboundary transmission infrastructure.

1.1 Increasing power demand

The ACEC countries' final electricity demand[4] over the last 25 years (from 1993–2017)[5] is summarised in Figure 1-1. It is evident from the figure that final electricity demand in the region grew at 3.3% each year (p.a.), on average, while GDP grew at a faster rate of 4.2% p.a. In 2017, final electricity demand was 449 TWh.

The electricity demand per capita remained low at 663 kWh, with an increase of just 113 kWh over the period. Egypt and South Africa alone accounted for 78% of the demand among countries in the ACEC, while their combined populations made up less than a quarter of the region's total population. In a few countries, electricity demand had grown rapidly, such as in Angola and Mozambique, where the average growth was 11% and 13% p.a., and in Ethiopia and Sudan where it was 9% and 10% p.a., respectively (UNSD, 2020).

4 Excluding own-use by generation plants.

5 The most comprehensive energy statistics for the ACEC countries are available from the United Nations. The latest data available is 2017 (as of June 2020). The timeframe of the "last 25 years" refers to the period between 1993 and 2017.

Figure 1-1: Final electricity demand, 1993–2017 (UNSD, 2020)

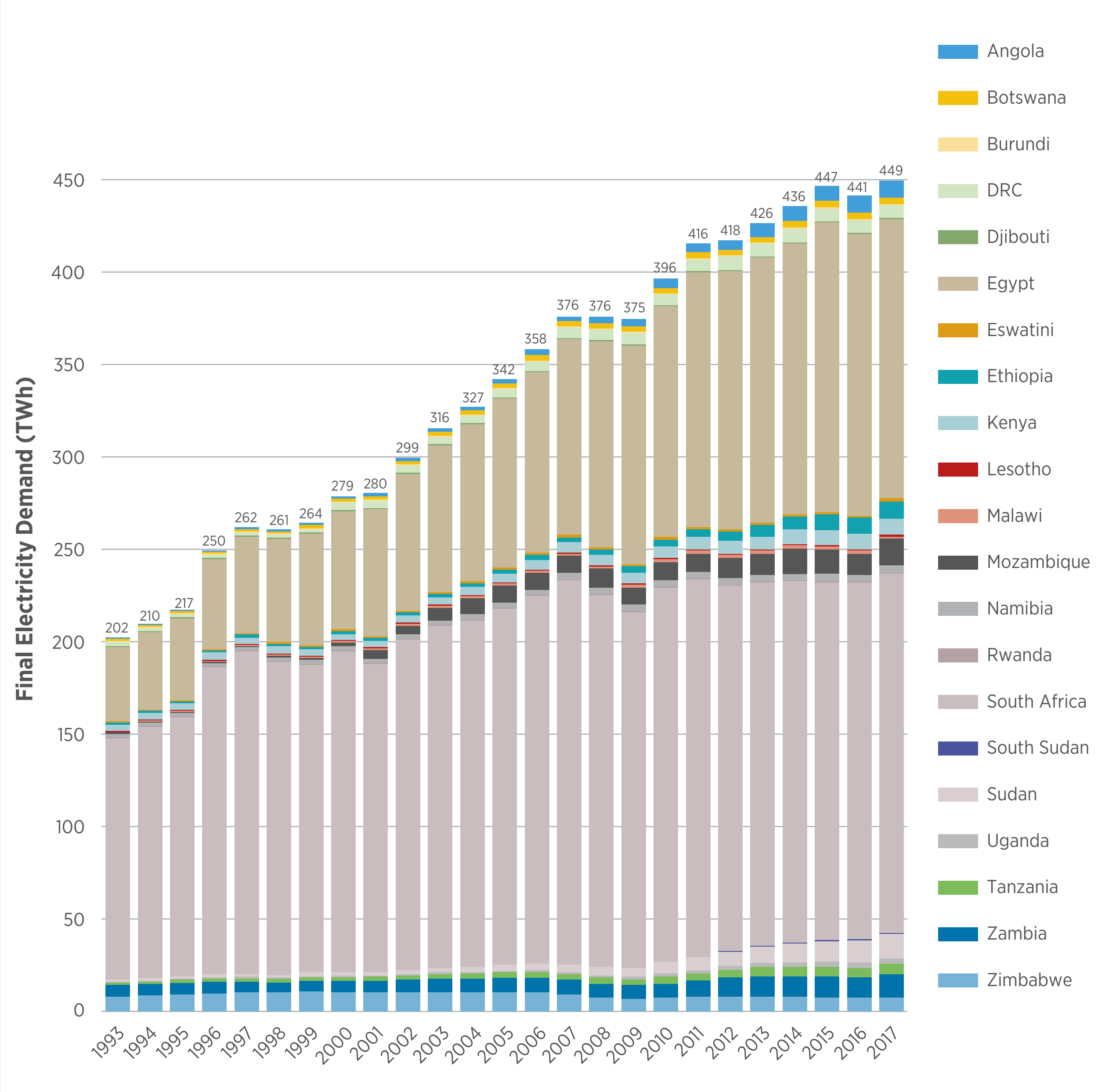
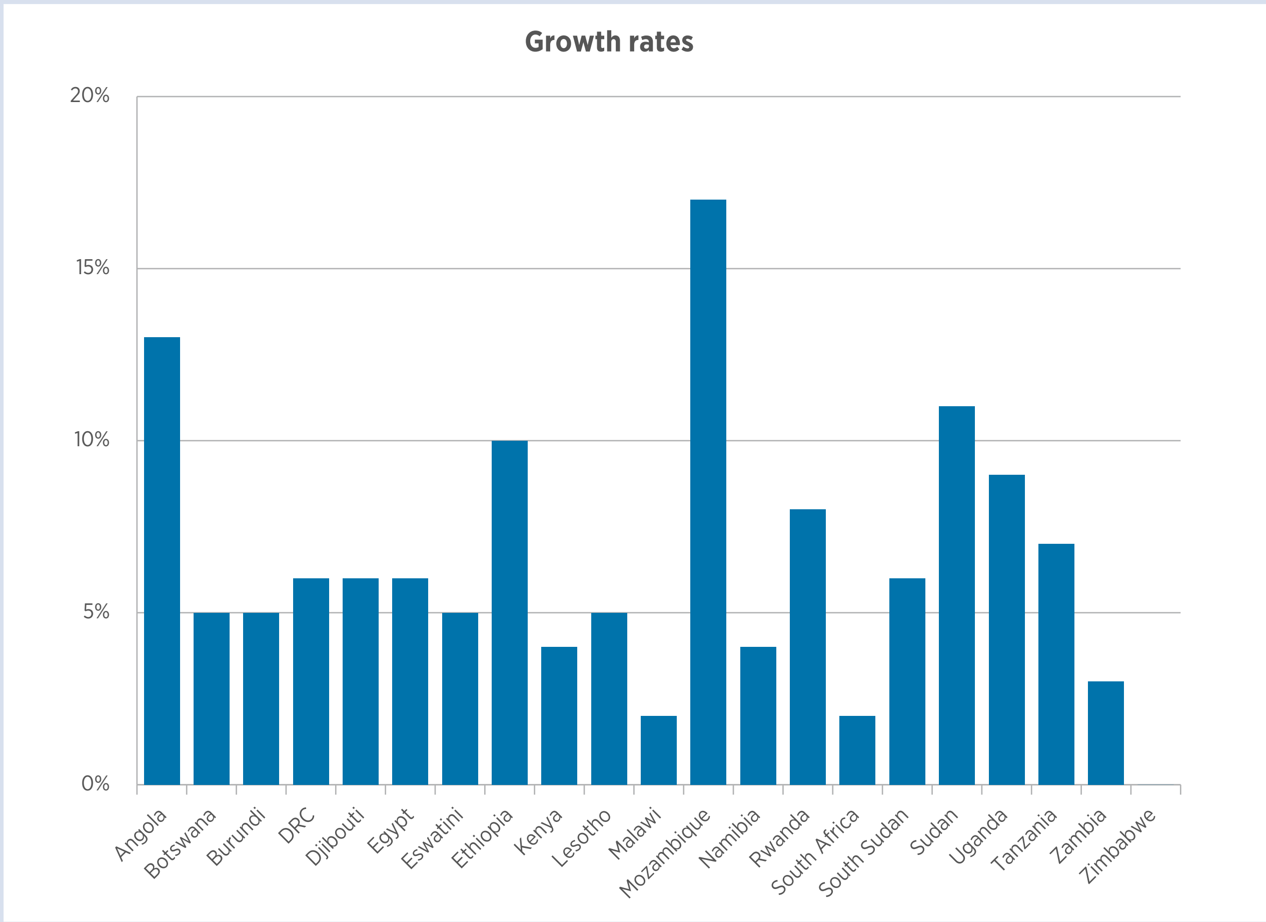


Figure 1-2: Average growth rate per annum of electricity demand in the ACEC[6], 1993–2017



Source: (UNSD, 2020).

Figure 1-2 summarises the average growth rate per annum of each country's electricity demand. Malawi, South Africa and Zimbabwe saw relatively low growth rates over the period (0–2%). In 2017, the EAPP and SAPP were self-sufficient in net electricity production as a region, where the export volume marginally exceeded import volume. In this region, some countries are heavily dependent on importing electricity from neighbouring countries including Botswana, Burundi, Eswatini, Lesotho and Namibia.

Electricity trade with countries external to the region are through power lines from Egypt to Libya, and from the Democratic Republic of Congo (DRC) to the Republic of Congo (Africa–EU Energy Partnership, 2017).

6 *Zimbabwe has seen a fall in electricity demand between 2006 (10.3 TWh) and 2009 (7.1 TWh). Data for South Sudan only available from 2013 onwards*

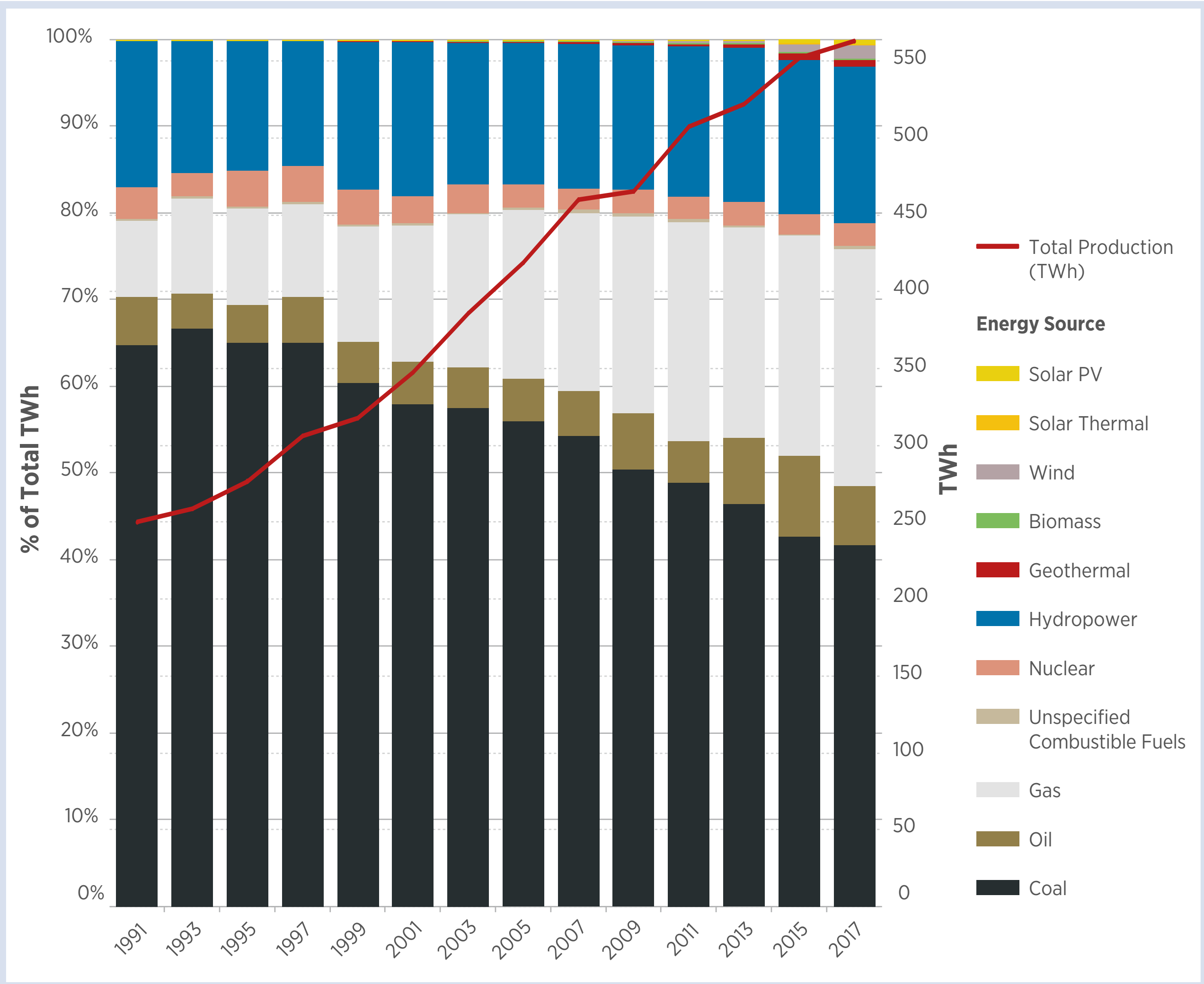
1.2 Heavily fossil-reliant power generation mix

In order to meet electricity demand growth, electricity production in the region more than doubled from approximately 248 TWh in 1991 to 563 TWh in 2017. The latest estimate of installed power generation capacity in the region in 2018 was approximately 145 GW (Platts, 2018).

As shown in Figure 1-3, coal has been the predominant source of power generation in Botswana, South Africa and Zimbabwe (IEA, 2020; UNSD, 2020). The existing Integrated Resource Plan in South Africa, for example, has emphasised the continued use of coal. The sector, including mining, employs a large number of workers.

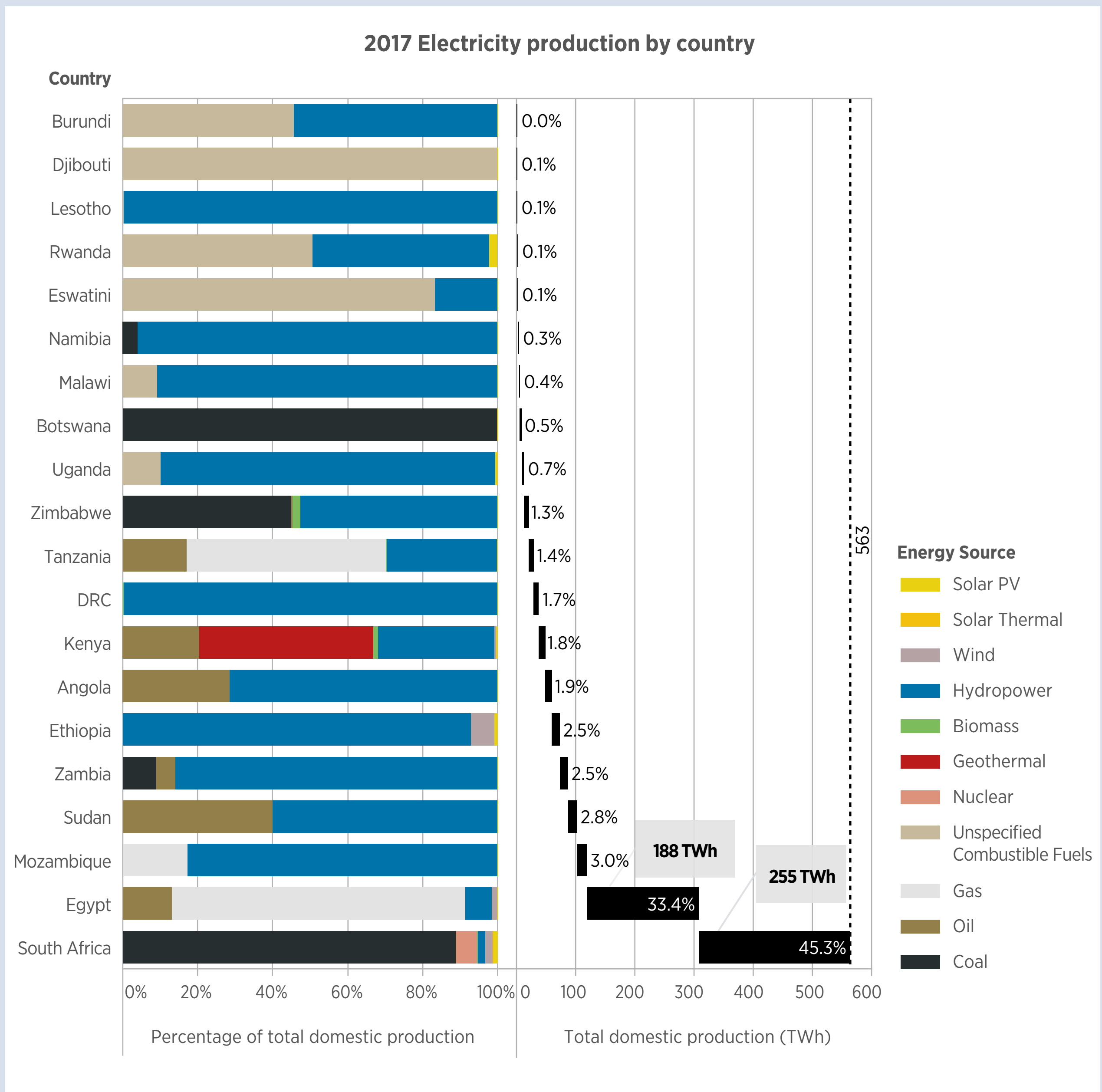
Regionally, the share of coal has steadily decreased over time, from approximately 62% of total generation in 1991 to 42% in 2017. This is a result of the increase in natural gas generation (from nine percent in 1991 to 28% by 2017), mainly in Egypt. Hydropower was the highest-producing renewable energy technology, making up 18% of generation. In the last decade, non-hydro renewables (i.e. solar PV, wind in Egypt and South Africa, and geothermal in Kenya) have begun to enter the market. At present, these non-hydro renewables make up three percent of total power generation.

Figure 1-3: Electricity generation by energy source in the ACEC countries, 2000–2017



Sources: (IEA, 2020; UNSD, 2020).

Figure 1-4: Percentage of power generation by energy source and in terms of overall electricity generation, as well as total generation in the ACEC countries, 2017



Sources: (IEA, 2020; UNSD, 2020).

Figure 1-4 presents the generation mix for 2017 in each country as a percentage of total power generation by fuel type, as well as the amount of generation by country. Corresponding to demand, South Africa and Egypt were the biggest producers of electricity in 2017, together accounting for 79% of total power generation in the region (45.3% and 33.4%, respectively). The dominance of coal and gas production in the region reflects the predominant generation mix of these two countries. Each country has 56 GW of total generation capacity. Out of 20 countries, 11 rely primarily on hydropower for more than 50% of their domestic electricity production.

1.3 Interconnectors

Total existing interconnector capacity among the ACEC countries is estimated to be at least 14.6 GW as of 2019. Some particularly notable transboundary capacities exist between Mozambique and South Africa (2 586 MW), Botswana and Zimbabwe (1 630 MW), Eswatini and Mozambique (1 613 MW), and Zambia and Zimbabwe (1 400 MW). The ZiZaBoNa transmission corridor is an example of an multinational project that connects Zimbabwe, Zambia, Botswana and Namibia. In addition, the Zambia–Tanzania–Kenya Interconnector will be the first on the continent to link the Eastern and Southern power pools.

It should be noted that the capacities of interconnectors between countries are not indicative of actual electricity trade. Some interconnectors – for instance, the 300 MW Caprivi Link between Namibia and Zambia – have low utilisation levels. The energy transmitted during the first year of operation was 400 GWh (EU–Africa Infrastructure Trust Fund, 2012). There are also bottlenecks in the SAPP central corridor backbone passing through Zimbabwe, which constrain trade in the SAPP market (UNECA, 2018).

Electricity flow volumes provide a more accurate picture of the level of electricity trade in the region. Total power traded on SAPP's day-ahead market was 1 870 GWh in 2019. Consistent transmission bottlenecks were observed in five out of 12 months in 2019, where more than 10% of matched volumes were not traded (SAPP, 2020). Total traded electricity (total gross import) within the ACEC region is estimated to have been over 30 TWh in 2016, corresponding to about seven percent of the final electricity demand (UNSD, 2020); utilisation is less than 30%. The trade is more prominent in the SAPP (total gross import is 12% of total final electricity demand).[7]

7 For calculation purposes, the figure reported in this section classifies the DRC to be in the SAPP and Tanzania to be in the EAPP.

OUTLOOK FROM THE EAPP AND SAPP MASTER PLANS

2

The EAPP and SAPP master plans[8] provide long-term regional electricity generation and transmission plans to guide future system expansions and then identify transboundary infrastructure projects with a view to establishing an integrated regional market. The revised EAPP Master Plan, produced by the Eastern African Power Pool in 2014, analysed the regional electricity system for 12 countries, under 21 scenarios. It was updated from the 2011 Master Plan to include the entire DRC, Libya and South Sudan. The SAPP Master Plan published in 2017 covered 12 countries and presented three main scenarios (referred to as 'components' in the master plan). Both master plans have a timeline to 2040. However, they do not reflect the reality of investment cost reductions and growth of renewables deployment in recent years, and both present a future dominated by fuel-based generation in their respective base cases for 2040 (see Figure 2-4). At the point of drafting this report, processes for updating the master plans have commenced (EU–TAF, 2020).

Box 2-1: Changing regional perceptions of renewables

The energy master plans of power pools and nation states are critical documents that are ultimately meant to guide the future development of clean energy systems in the next two to three decades. In many cases, however, even the most recent master plans in Africa feature a significant share of fossil fuel technologies, reflecting the common historical perception that they are necessary both for development and to provide "baseload" generation that variable renewable energy like wind and solar cannot.

In the past decade, however, VRE has become by far the lowest cost source of new electricity in many parts of the world, even dropping below the production cost of already-installed fossil fuel energy in some places. Simultaneous advances in grid management have made possible the running of modern economies on very high – if not total – penetrations of VRE. These realities are yet to be reflected in policy making in Africa, where many still perceive a need for baseload generation or believe that renewables are too costly.

Updating regional perceptions to reflect the latest facts on the ground will be vital in meeting the urgent logic of the Paris Agreement and complying with scientific and mathematical boundary conditions to GHG emissions that are so often given relatively low priority. Embracing these most recent trends is also key to the development of interconnectors, which are critical to the African Energy Transition and can also enable the growth of VRE. Policy makers and modelers have reason to believe in an energy future based on VRE in order to give the go-ahead for plans to build the interconnectors, which in turn would lead to enhanced growth in installed VRE capacity.

8 *Unless otherwise stated, for the DRC and Tanzania, which are in both the EAPP and the SAPP, aggregated numbers for the region use the data from the SAPP master plan.*

2.1 Demand prospects

Historically, power demand has been growing in the region. Demand growth over historic periods is reported using different metrics and timeframes in the EAPP and SAPP master plans, i.e., the former with the electricity demand including losses (2000–2014), and the latter with sent-out peak[9] demand (2006–2016). The differing scopes make direct comparisons of the reported demand challenging. According to these, the EAPP experienced an average growth in electricity demand (TWh) of 7–8% p.a. from 2004 to 2014. Demand is still largely suppressed due to low installed capacities and unreliable supply. The SAPP saw an average growth of 0.4% p.a. in peak demand (MW). The master plans account for electrification rate projections of different countries to varying extents.

Table 2-1 shows the methodologies used by the master plans to make projections of sent-out electricity demand.

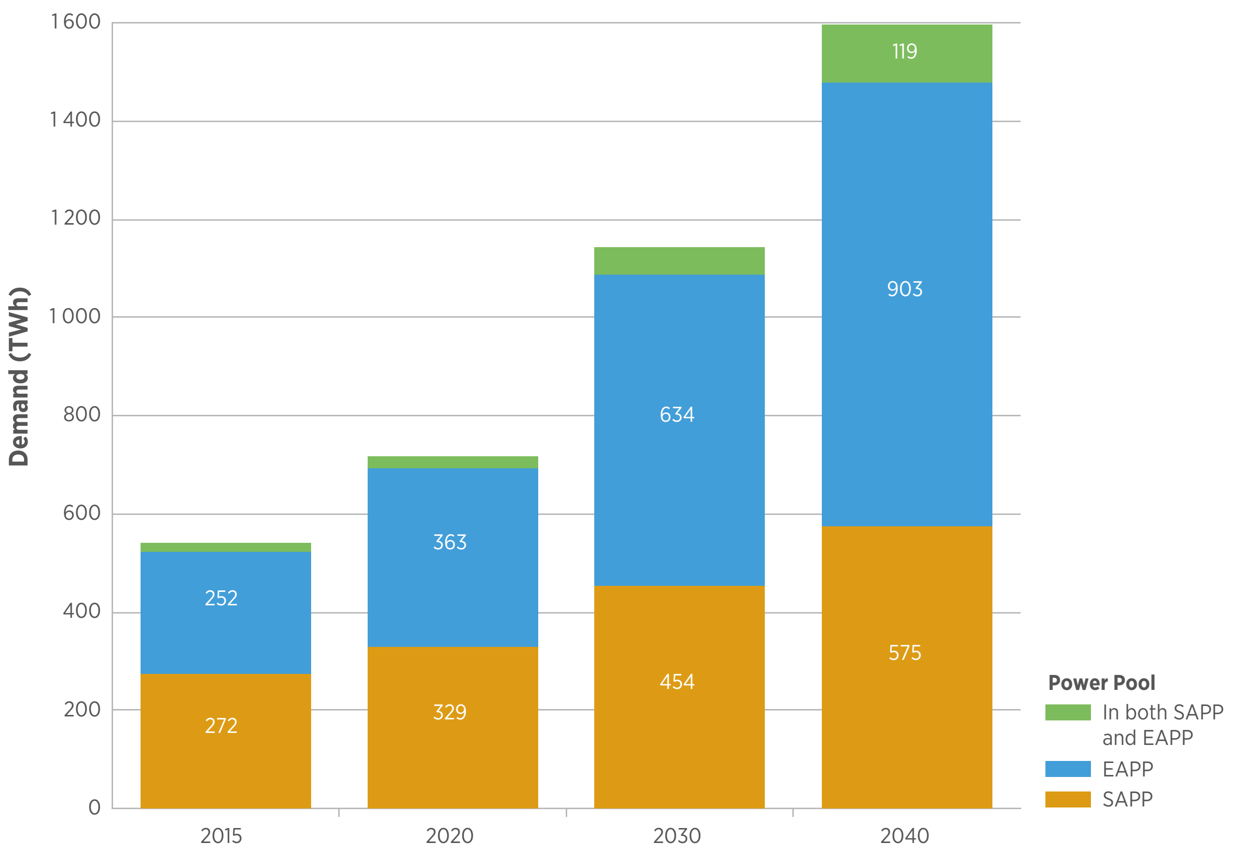
Table 2-1: Methodologies used by the EAPP and SAPP master plans for projecting sent-out electricity demand

EAPP master plan	SAPP master plan
From 2020 to 2040, regional electricity demand is estimated to grow at 5% p.a., on average. Individual country forecasts were linearly adjusted from their last year of projection to exhibit a 6% p.a. growth rate towards 2030 and a 3% p.a. rate between 2030 and 2040, to reflect the assumption that electricity access would have increased. Two alternative forecasts of demand were formulated, with a 10% decrease and increase in demand, respectively.	The SAPP master plan investigated projected trends for various drivers of power demand, such as population growth, GDP growth and increased electricity access through urbanisation. The SAPP master plan adopted a more nuanced and country-specific approach in comparison to the EAPP master plan. Individual country demand forecasts were derived from the national demand forecasts of the SAPP member countries, with different methodologies being used by different countries. On average, sent-out electricity demand (TWh) in the region is estimated to grow at 3.4% p.a. for the Base forecast. An alternative Low demand forecast is also developed with assumptions on lower levels of suppressed demand, economic prospects and electrification plans. The Low forecast projects a demand growth of 2.1% p.a.

9 *Sent-out demand refers to the demand after self-consumption of generating units, prior to transmission and distribution losses. It is to be differentiated from final demand, which is the power consumption by consumers.*

Figure 2-1 shows the aggregated projected electricity demand for SAPP and EAPP countries[10] from 2015 to 2040, as reported by the two master plans in conjunction with additional research outlined in Table 4-1. By 2030, total demand in the region is projected to double to 1143 TWh (from 541 TWh in 2015). By 2040, total demand is further projected to triple compared to 2015 values, to 1595 TWh. Egypt drives the demand increase in the EAPP, almost tripling from 216 TWh to 592 TWh between 2015 and 2040. Egypt accounts for two-thirds of EAPP's demand in 2040, while South Africa makes up about half of SAPP's demand. Yearly per capita consumption would increase from 992 kWh to 1622 kWh in the SAPP, and from 717 kWh to 1516 kWh[11] in the EAPP. This is especially driven by increased electrification rates and economic activities.

Figure 2-1: Projected electricity demand from 2020 to 2040 for the SAPP and EAPP countries, according to master plans and additional research



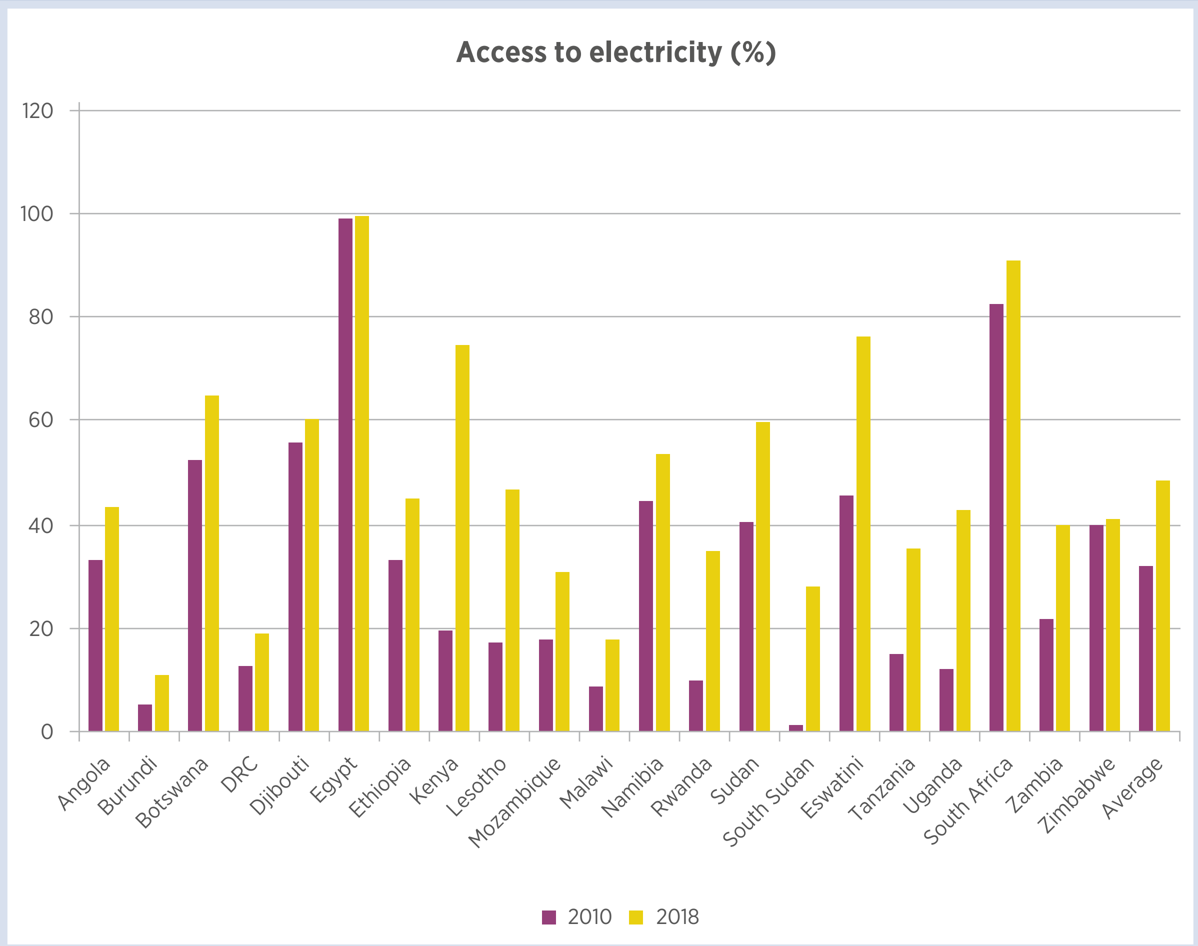
10 *The DRC and Tanzania are present in both power pools and are each tabulated only once according to their projections in the SAPP master plan, as this publication is more current.*

11 *Using the World Bank's total population projections (World Bank, 2019a).*

Box 2-2: Energy access

Expanding access to energy through electrification is an important priority for most ACEC countries. The average rate of access is similar for the two power pools, although the variance within the power pools are large. From 2010 to 2018, the population with access to electricity has increased from 32% to 48% in the ACEC countries (World Bank, 2019b). Figure 2-2 compares access to electricity in 2010 to that of 2018. Countries like Eswatini, Kenya, Lesotho, Rwanda, South Sudan and Uganda had made enormous strides in expanding energy access.

Figure 2-2: Access to electricity (% of population)



Source: (World Bank, 2019b).

While the United Nations has targetted universal access by 2030, national targets may deviate with regards to the timeline. Tanzania, for example, has set a target of achieving 75–90% electrification of households by 2035.

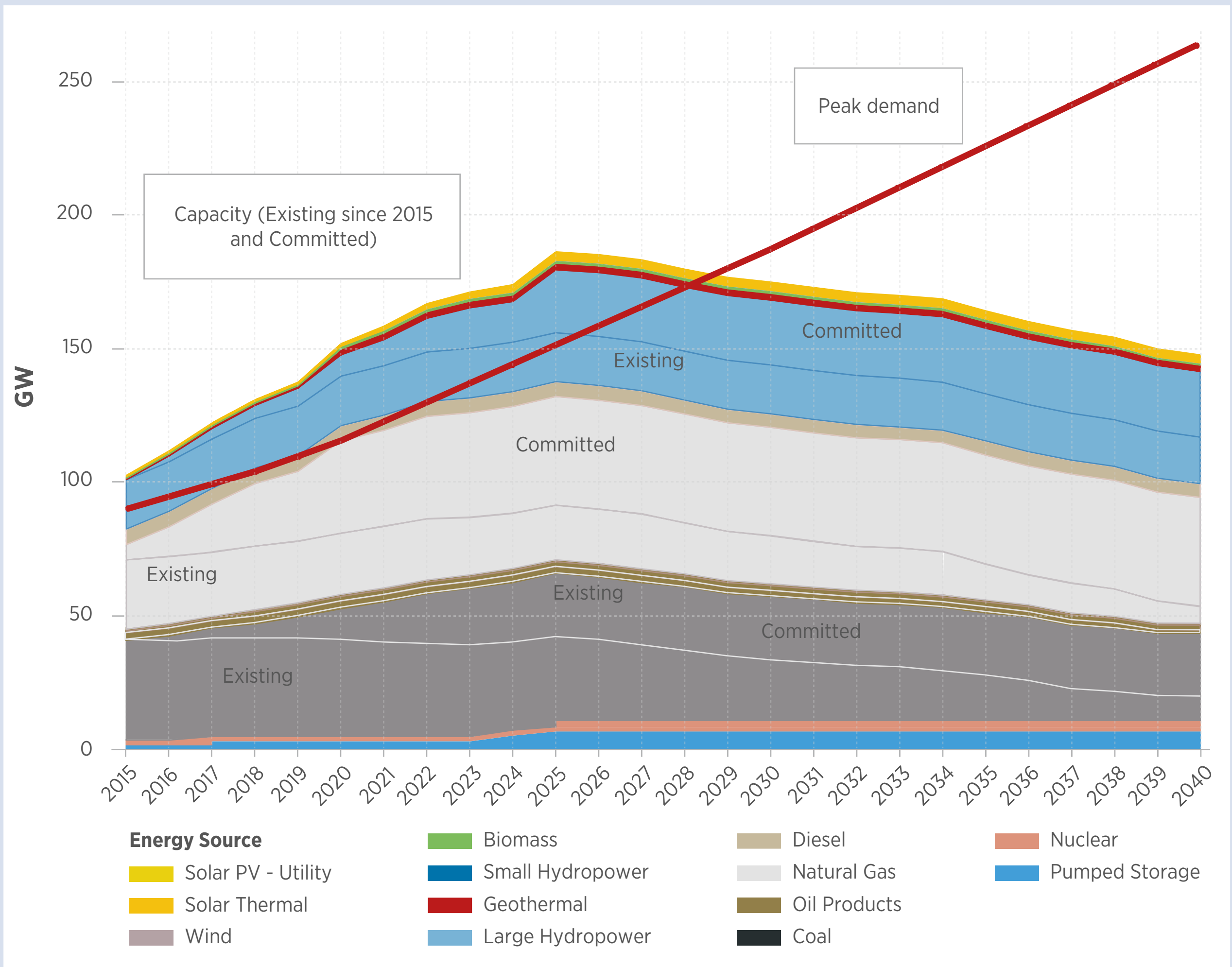
Although not the focus of this study, it should be acknowledged that mini-grids and stand-alone systems in Africa can help to advance rural electrification, while at the same time increase the penetration of RE, particularly helpful in addressing low electrification rates, the obstacle of high construction costs of transmission lines, and low consumption in unelectrified areas due to low economic activities. Much work has been produced to examine the options for electrification, such as through the Reference Electrification Model (REM), (MIT, 2018) and the Global Electrification Platform (World Bank, 2020).

2.2 Power generation capacity expansion

As of 2015, about 100 GW of mainly coal and natural gas units exist in the EAPP and SAPP. Based on the plants' lifetimes and build years, by 2040, half of that capacity will have retired. Based on those committed[12] as of 2015, the retired plants will be replaced by approximately 100 GW of projects (see Figure 2-3) during the decade leading to 2025, including 40 GW of gas, 25 GW of hydro and 24 GW of coal.

If no additional generation capacity beyond what is committed were built, there would be approximately 148 GW of generation capacity in 2040 – the same as today. The observed deficit between projected peak demand (263 GW), and existing and committed capacity will amount to about 115 GW by 2040. This is despite the current surplus capacity in the EAPP, which has overcapacity in Ethiopia, Kenya and Uganda and undersupply in Tanzania.

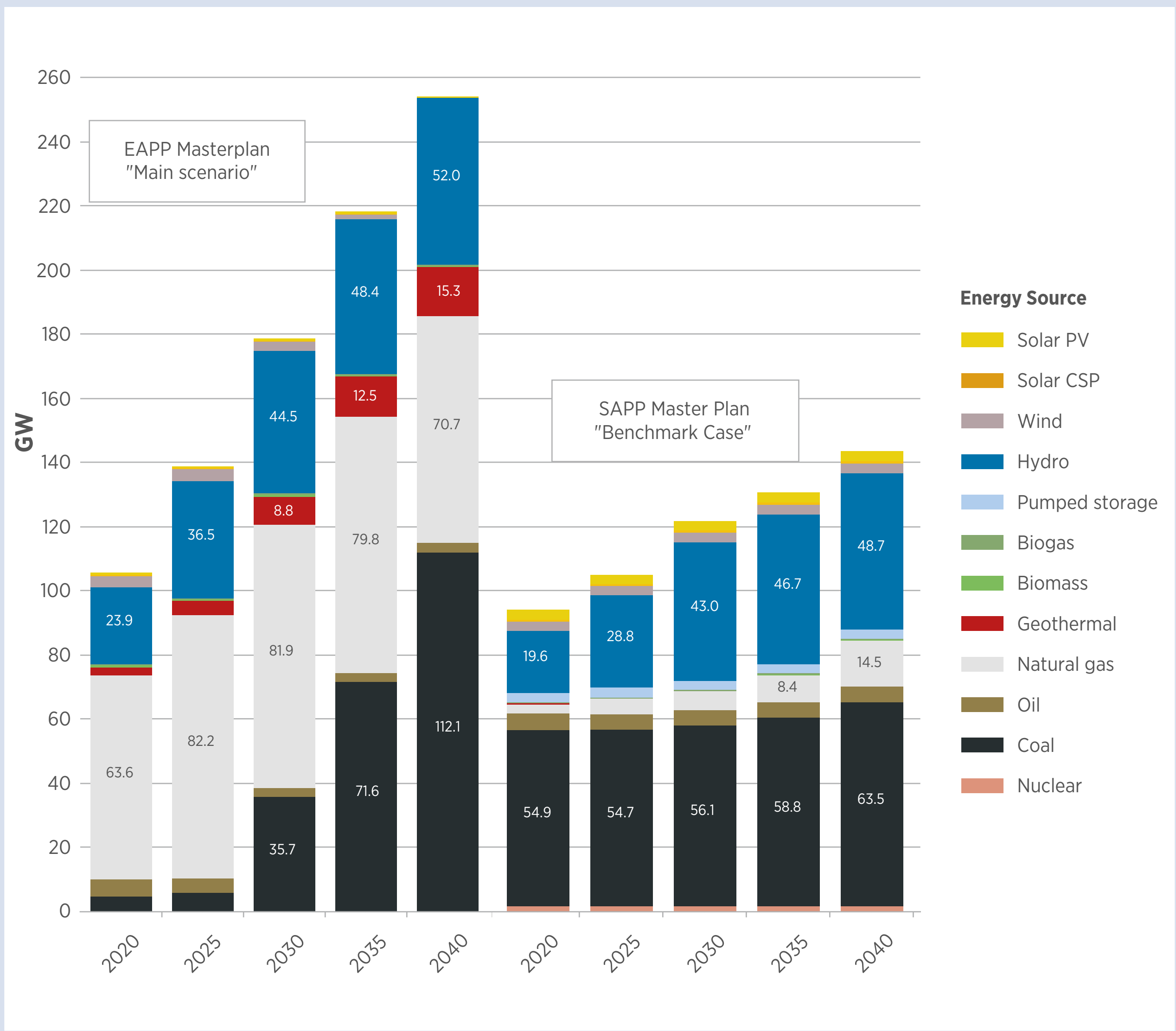
Figure 2-3: Peak demand and capacity mix timeline including committed plants and retirement schedule of existing plants in the ACEC countries, 2015–2040



12 *Committed projects are, as of 2015, under construction or commissioned to be built at fixed dates, having already reached financial closure and received all necessary approvals, and sites of the projects are specified. These projects are included as part of the known current and future energy mix.*

In the EAPP master plan, in addition to the "main scenario", which acts as a reference, there are also scenarios formulated for high renewable future, different demand trajectories, transmission capacity expansion plans, hydro resource availabilities and costs, the presence of carbon tax, export levels, nuclear generation, gas prices, interest rates and reserve margin requirements. Of which, typically only a single parameter is varied per scenario.

Figure 2-4: EAPP and SAPP's capacity mix until 2040 based on the respective master plans' reference plans[13]



Source: (EAPP, 2014; SAPP, 2017).

13 In this figure, both the EAPP and the SAPP master plans include the DRC and Tanzania.

Box 2-3: "Reference" scenarios: What they are and how this report uses the term

A “reference” scenario is often one that serves as a point of comparison for other scenarios. The implications of a reference scenario may differ depending on the context of the study. Sometimes, this refers to a projection into the future based on existing policies or consumption habits, also known as “business-as-usual” (BAU). In other cases, the “reference” may refer to the most likely pathway. In this report, a reference scenario is one with assumptions mostly aligned with those in the master plans, supplemented by the use of the best available information on renewable technologies from IRENA’s database, while unconstrained generally for generation and capacity expansions. Hence it is the pathway that incurs the least economic cost based on existing information. A corresponding scenario in the EAPP master plan is the “main scenario”. In the SAPP master plan, it is the “benchmark case”. The term is often used interchangeably with “base case”, “baseline”, “benchmark” etc.

In the SAPP master plan, in addition to a “benchmark case” (also known as Component A), there are alternative scenarios to account for security of supply with “full” (known as Component B) or “realistic integration” (Component C) of the power pool. The “benchmark case” reflects the plans for generation and transmission in each country based on national master plans to 2040 (or extended to 2040), while the “realistic integration” case includes a series of sensitivity runs, including one with high renewables.

Figure 2-4 shows the reference plans from the EAPP and SAPP master plans (“main scenario” and “benchmark case” respectively). In the EAPP, total generation capacity is set to increase from 106 GW (2020) to 254 GW (2040) (including Libya – 22 GW in 2040). Gas increases slightly, but coal makes up the majority of the capacity additions. Coal features prominently in the future plans and is expected to grow from a share of 4.5% (4.8 GW) to make up 44% (112 GW) of total generation capacity in region by 2040 – higher than in the SAPP. In 2040, renewable energy sources will make up 27% (6.9 GW) of total generation capacity. However, the majority of this share comes from hydropower and geothermal sources, while VRE sources only constitute a 0.2% share (EAPP, 2014). For the EAPP, the reality so far is not far from the master plan. Since 2014, fossil fuel technology capacity had grown to approximately 74 GW in 2019 (IRENA, 2020a).

In the SAPP master plan, total generation capacity (including pumped storage) increases from 94 GW to 143 GW over the two decades before 2040. Renewable energy sources increase to 41% (58 GW) of total generation capacity. Hydropower is the key driver in the growth of renewables uptake, while VRE capacity makes up a share of 4.7% (6.7 GW). Coal continues to feature prominently at 44% of total capacity (SAPP, 2017).

As noted earlier in this section, both master plans also feature scenarios with higher renewables penetration in the capacity mix in contrast to their reference plans. These are the “renewable scenario” in the EAPP master plan and the “high renewables” sensitivity (SC4) under the “realistic integration case” in the SAPP master plan.

Table 2-2: Comparison of the 2040 capacity share for EAPP's "main" and SAPP's "benchmark" scenarios, with renewable scenarios; MW values in parenthesis

	EAPP		SAPP		
	Main	**Renewable**	**Benchmark**	**Realistic Integration**	**High RE sensitivity (SC4)**
Biogas	0.1% (150)	0% (150)	0% (18)	0% (18)	0% (18)
Biomass	0.2% (452)	0.1% (452)	0.1% (81)	0.1% (141)	0.5% (727)
Geothermal	6% (15 300)	3.9% (15 300)	0.1% (200)	0.2% (200)	0.1% (200)
Hydro	20.5% (52 038)	14.6% (57 153)	34.7% (48 745)	33.5% (42 462)	27.5% (42 390)
Pumped storage	0% (0)	0% (0)	2.1% (2 912)	2.3% (2 912)	1.9% (2 912)
Solar	0.2% (575)	0.1% (575)	2.7% (3 746)	2.9% (3 646)	12.1% (18 676)
Wind	0% (0)	33.8% (132 262)	2.1% (2 994)	2.4% (2 994)	11.9% (18 287)
Total RE share	**26.9%**	**52.6%**	**41.8%**	**41.3%**	**54.0%**
Coal	44.1% (112 073)	19.4% (76 078)	45.2% (63 454)	45.3% (57 419)	36.7% (56 520)
Natural gas	27.8% (70 710)	27.2% (106 611)	10.3% (14 538)	10.3% (13 108)	0% (0)
Oil	1.2% (2 935)	0.7% (2 935)	3.5% (4 912)	3.9% (4 924)	0% (0)
Thermal (exl. Coal)	0% (0)	0% (0)	0% (0)	0% (0)	10.2% (15 700)
Total thermal share	**73.0%**	**47.4%**	**59.0%**	**59.5%**	**46.9%**
Nuclear	0% (0)	0% (0)	1.3% (1 800)	1.4% (1 800)	1% (1 570)
Others (waste and peat)	0.1% (183)	0% (183)	0% (0)	0% (0)	0% (0)

Sources: : (EAPP, 2014; SAPP, 2017).

The high renewable energy scenario of the EAPP master plan replaces primarily coal generation in the reference plans with the large-scale introduction of wind generation, causing renewable to account for 50% of total generation capacity by 2040. The renewable-friendly sensitivity ("high RE sensitivity – SC4") in the SAPP master plan reduces coal and other thermal generation in the "benchmark case" by about 12%, as they are replaced by modest increases of wind and solar PV. This causes the capacity share of renewable sources to reach over 50%, with half of the share coming from non-hydro renewable technologies. No further short-term storage options are considered other than pumped storage (in the SAPP).

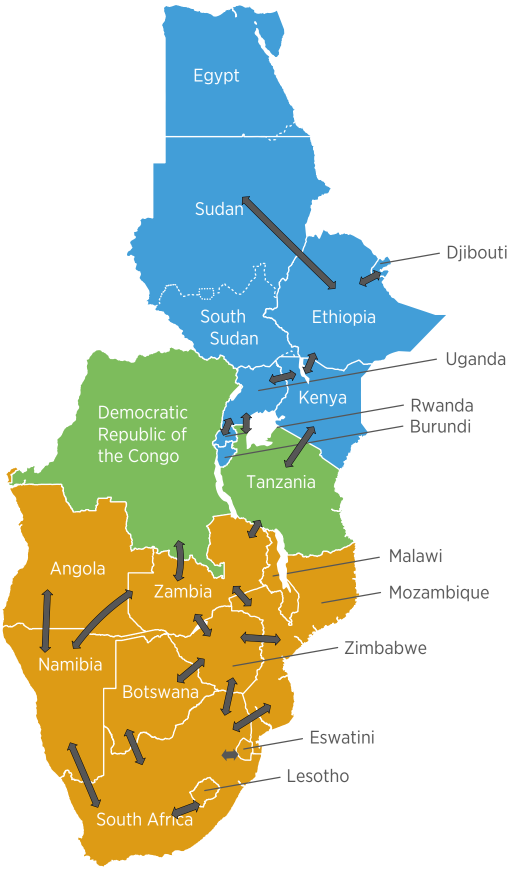
2.3 Interconnector capacities

Both the EAPP and SAPP present the ambition to increase electricity trade and their respective master plans identify additional transmission infrastructure projects (i.e. those either under construction or committed). Figure 2-5 shows the region's existing and committed interconnector lines and capacities in MW according to the master plans (EAPP, 2014; SAPP, 2017), with minor updates based on a World Bank-funded and Aurecon-led SAPP–EAPP Interconnector Impact study (Aurecon, 2018). The committed projects are defined based upon current government plans and regional or bilateral agreements, and are to come online before 2028 – although in principal there can be changes (EAPP, 2014; SAPP, 2017). Committed projects which had been projected to be built before 2019 are included as "existing (as of 2019)" if already operational. The table does not include candidate transmission lines, which have not yet reached financial closure, such as some projects featured under the PIDA PAP 1, the Nile Basin Initiative, or the DRC–South Africa[14] and Ethiopia–Sudan interconnectors.

In both power pools, the frequency of the interconnected transmission system is controlled at 50 Hz under normal operation.

14 *Although the DRC and South Africa do not share a border, there has been an inter-utility study on a HVDC link terminating at Merensky, from the Inga via the Katanga/Copperbelt area.*

Figure 2-5: Existing and committed interconnections and respective capacities (MW) in 2019



		Capacity (MW)
Zambia – Zimbabwe	[Zizabona] Livingstone-Victoria Falls, 330AC	400
	Kariba North-Kariba South, 330AC	1 400
Tanzania – Zambia	[ZTK] Kasama Nakonde-Tunduma Mbeya, 400AC	750
Tanzania – Uganda	Masaka-Kyaka, 132AC/220AC	431
South Africa – Zimbabwe	[Mozisa] Nzhelele-Triangle, 400AC	500
South Africa – Eswatini	Mahamba-Normandie/Edwalieni-Camden, 132AC/400AC	1 344
Rwanda – Uganda	Mbarara-Birembo, 220AC	363
Namibia – Zambia	[Zizabona] Gerus-Sesheke, 400AC	650
Namibia – South Africa	Kokerboom-Aries/Harib-Aggeneis, 400/220AC	241
	Obib-Oranjemond-Gromis 400kV, 400AC	750
Mozambique – Zimbabwe	[Mozisa] Inchope(Matambo-Songo)-Orange Grove (Triangle-Msoro), 400AC	400
	Songo - Bindura, 400AC	500
Mozambique – Zambia	Songo-Msoro, 400AC	200
Mozambique – South Africa	Apollo-Songo, 533HVDC	1 200
	Maputo (Motraco)-Arnot/Ressano Garcia-Komatipoort, 400AC/132AC	1 386
Mozambique – Eswatini	Maputo-Edwaleni/Maputo-Edwalieni2/Matola-Kalanga, 400AC/400AC	1 613
Lesotho – South Africa	Maboti-Tweespruit/Khukhuna-Clarens, 132AC/132AC	217
Kenya – Uganda	Bujagali/Tororo-Lessos, 400AC	400
Kenya – Tanzania	[ZTK] Kenya -Tanzania (Isinya-Arusha) 400AC	600
Ethiopia – Sudan	Existing Sudan-Ethiopia, AC	200
Ethiopia – Kenya	Ethiopia border-Suswa, 500HVDC	2 000
DRC – Zambia	Lumumbashi-Luano, 220AC	120
Djibouti – Ethiopia	Existing Ethiopia-Djibouti, 220AC	180
Botswana – Zimbabwe	[Zizabona] Pandamatenga-Victoria Falls, 330/400AC	400
	Phokoje-Insukamini/Francistown-Marvelm, 400/220AC	1 630
Botswana – South Africa	[BOSA] Isang-Watershed B, 400AC	800
	Gaborone-Kopfontein/Gaborone-Spitskop/Segoditshane-KOFF, 132AC	129
	Phokoje-Matimba, 400AC	420
Angola – Namibia	[ANNA] Omatando-Xangongo/Baynes-Cahama, 400AC/400AC	700

Status

Existing (as of 2019) committed

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

Sources: (EAPP, 2014; SAPP, 2017).

Ground mounted solar power plants in Africa
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RENEWABLE RESOURCE POTENTIAL IN SOUTHERN AND EAST AFRICAN COUNTRIES

3

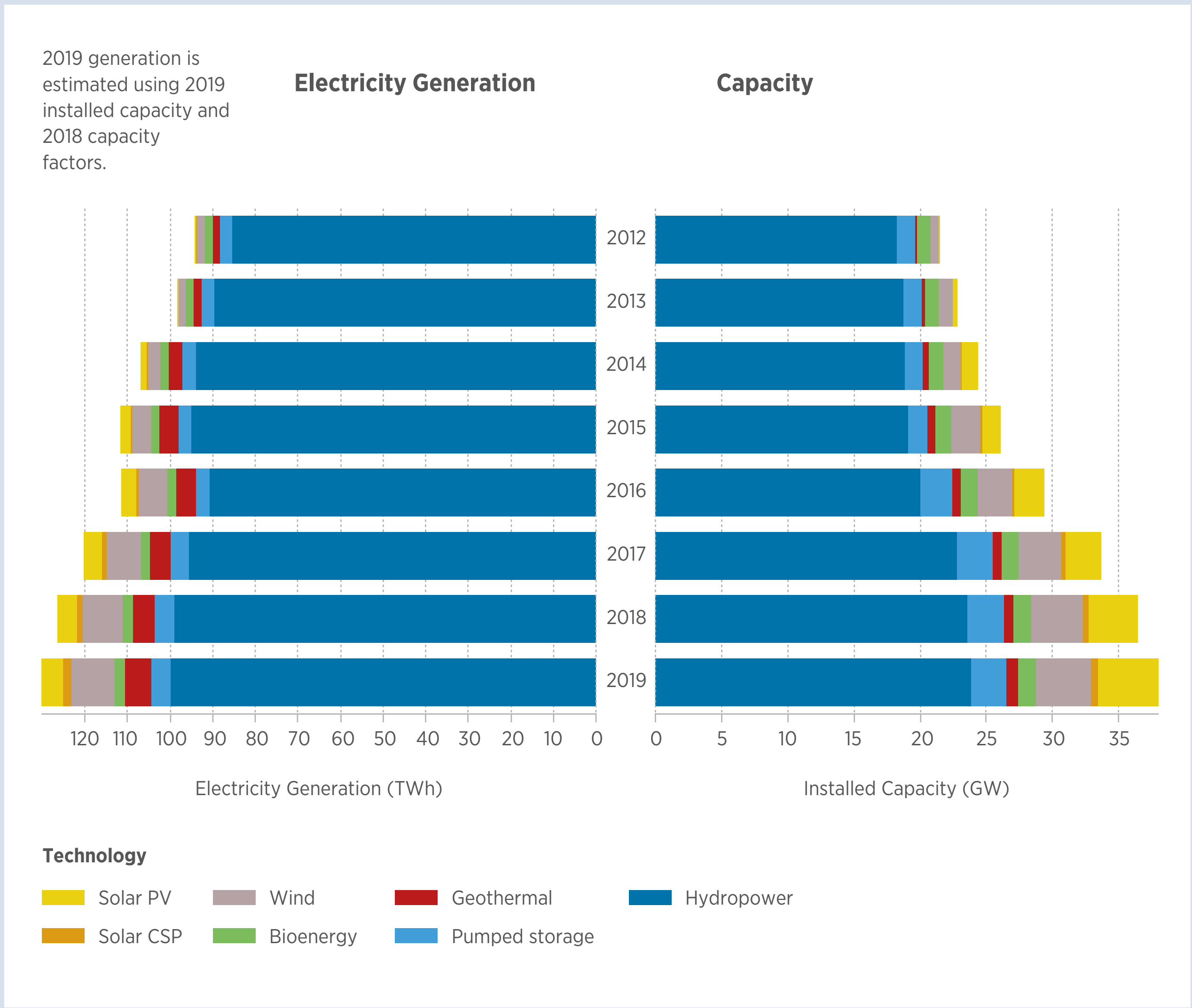
This chapter presents recent renewable energy deployment trends and contrasts them with available renewable resources in Southern and East Africa, with a focus on solar PV and onshore wind. Specific solar PV and onshore wind project zones are presented here for their resource quality based on defined criteria, as a pre-screening step prior to further analysis. Solar CSP, hydropower and geothermal resources are also assessed.

3.1 Renewable energy deployment trends

Although conventional fuel is still the main source of electricity generation, developments in recent years show that renewable energy uptake has been expanding quickly in Southern and East Africa. Figure 3-1 shows the region's electricity generation (2012–2019, with 2019 estimated) and installed capacity (2012–2019) of renewable energy sources (IRENA, 2020a). As can be seen in the figure, wind capacity increased from 647 MW in 2012 to 4 134 MW in 2019. During the same period, solar PV capacity increased from 89 MW to 4 828 MW. Correspondingly, electricity generation from wind grew from 1.8 TWh to 10 TWh, while generation from solar PV increased more than sixty-fold, from 0.1 TWh to 6.0 TWh.[15] Recent droughts in Angola, Egypt, Mozambique, Zambia and Zimbabwe have resulted in reduced hydropower generation in some years.

15 The accounting periods for capacity and generation data can vary, therefore resulting in less than proportionate growth in generation in 2018-2019 if generation data from the newest capacities are not available. As an example, a 310 MW Lake Turkana wind power plant was connected to the grid in in Sep 2018, but this information was not captured by the primary sources that has an accounting period from July 2017 to June 2018.

Figure 3-1: Electricity generation by renewables (2012–2019) and installed capacity of renewables (2012–2019) in ACEC countries

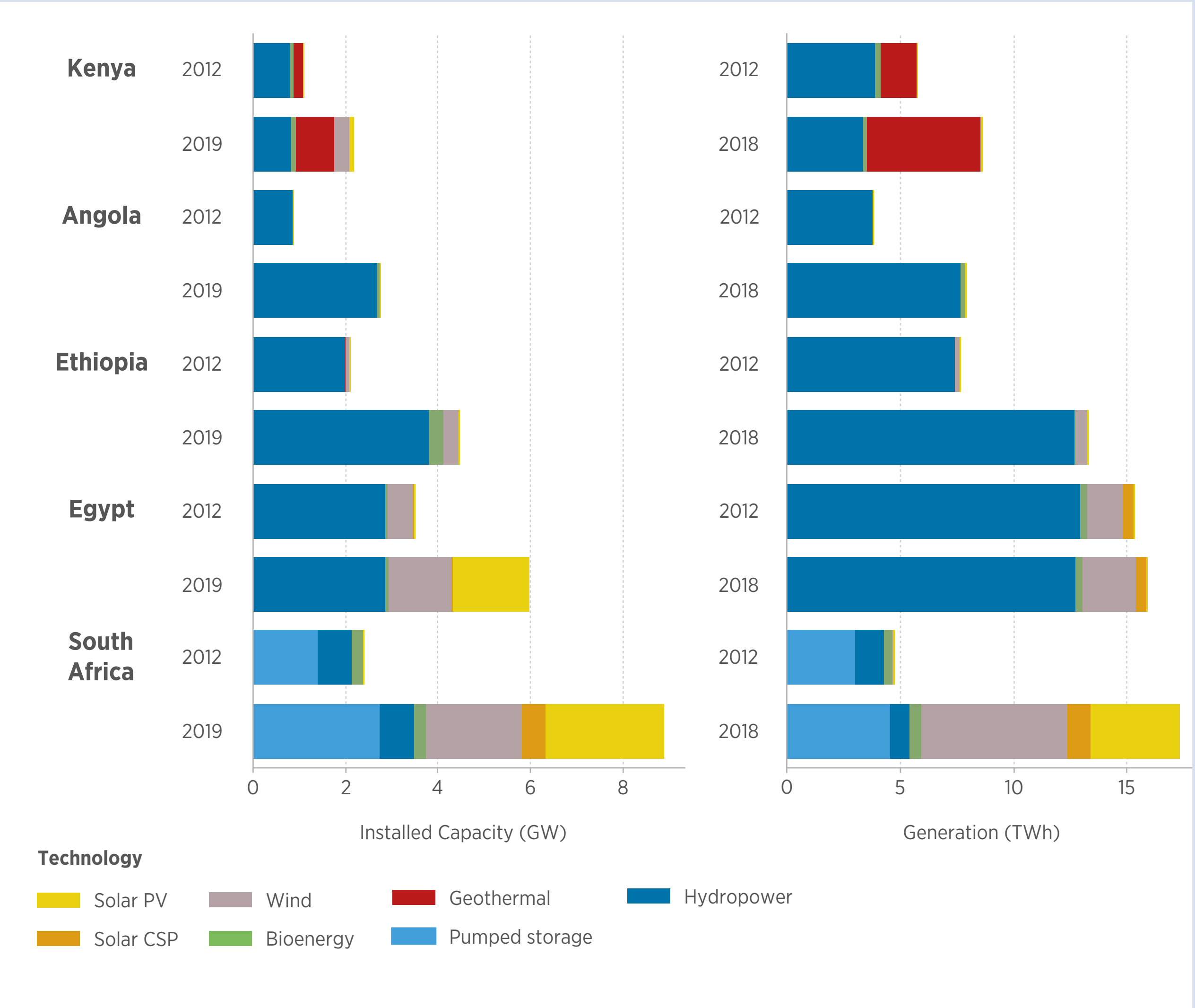


Source: (IRENA, 2020a).

Most of the growth in wind capacity expansions are a result of capacity expansions in Egypt, Ethiopia, Kenya and South Africa. Figure 3-2 shows the 2012 and 2019 capacities in the countries with the largest increases in renewable capacities, and their respective generation in 2012 and 2018. Growth in solar PV capacities has been driven by expansions in South Africa and Egypt. Such growth is driven by the policies adopted by these countries that are conducive to renewable energy deployment.[16] Meanwhile, Kenya has greatly expanded its geothermal capacity, contributing to an increase in the percentage of Kenyans with access to electricity from 41% in 2012 to 64% in 2017, according to the World Bank (Rosen and Sobecki, 2018). In addition to these expansions in renewable energy, hydropower capacity has increased most notably in Angola and Ethiopia.

16 *For example, South Africa's particularly important increase in solar and wind capacity was enabled by the country's Renewable Energy Independent Power Producer Procurement Programme, a competitive tender process designed to allow private investments in renewable energy (Eberhard and Naude, 2017).*

Figure 3-2: Installed capacities of renewables in 2012 and 2019 in countries with the largest growths in RE capacities, and their respective generations in 2012 and 2018 (latest year of data available)



Source: (IRENA, 2020a).

3.2 Solar PV and onshore wind potential

The continent is known to have massive untapped solar and wind potential. From forthcoming, updated analysis, IRENA's estimates suggest that technical potential for wind and solar PV are over 147 TW and 337 TW, respectively, in the region.[17] In order for these theoretical technical potentials to be considered as tangible investment options in the planning process, they were translated into a narrower concept of renewable zones. IRENA's *Multi-criteria analysis for planning renewable energy* (MapRE) study, jointly undertaken with Lawrence Berkeley National Laboratory, employs this translation for the region.

An overall resource assessment[18] is first conducted, then, a subset of the resource potentials are identified as continuous areas in the order of 30–1 000 km². MapRE analysis for the region identified 2 732 zones for utility-scale solar PV (>10 MW) and 1 558 zones for wind, each corresponds to a collective potential of 6.97 TW and 2 TW (IRENA and LBNL, 2015a).[19] Currently deployed capacities (8.96 GW) are approximately 0.1% of that total potential (IRENA, 2020a).

Box 3-1: Multi-criteria analysis

The multi-criteria analysis within the **MapRE analysis** screens the zones based on user defined weights for several criteria. For this report, the criteria for ranking solar PV zones are LCOE (levelised cost of electricity) (50% weighting) and distance to load centre (50% weighting), while those for ranking wind zones are LCOE (50% weighting), distance to load centre (25% weighting) and capacity value ratio[20] (25% weighting). Zones screened in this process are used in the subsequent SPLAT modeling analysis, that determines whether the investment in the RE projects in a given zone is economically viable, and if so, what the optimal timing of the investment is, taking into account the dynamic interplay of different system components. Examples of system interactions that are not included in the MapRE analysis, but are in the SPLAT modelling analysis, are hourly demand, generation by other plants, and interconnector flows. The link between the zoning analysis presented in this chapter and the SPLAT model analysis presented in the next chapter is described in the schematic in Figure 3-1.

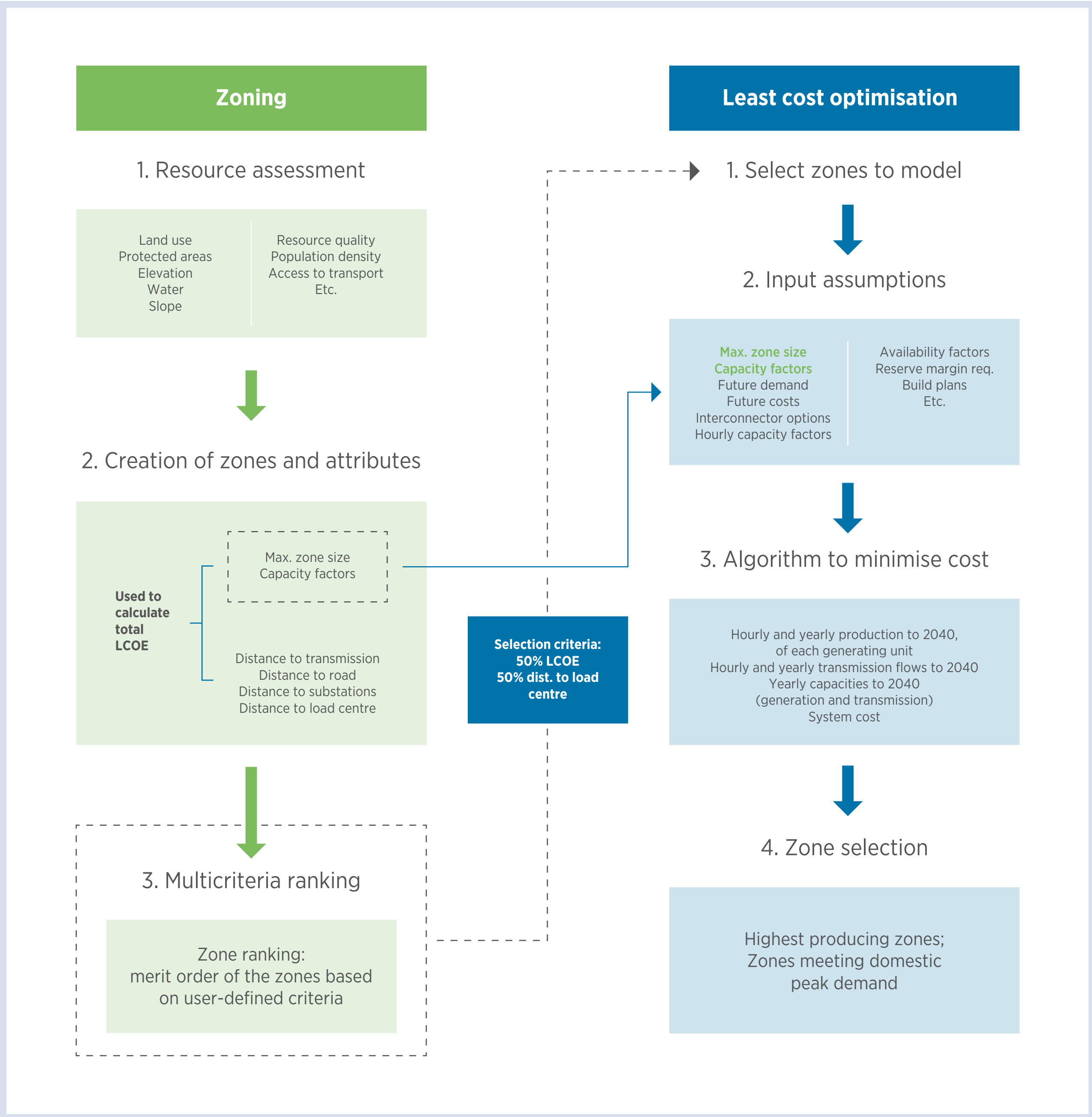
17 The potential estimates from this assessment consider all areas after applying exclusion zones to be fit for renewables deployment. There may be other factors which can restrict the land suitable for renewable energy deployment, such as the practicality, legal and social–economic implications of renewable energy deployment. Often, a scaling factor as low as 1% could be applied to the potential estimate to account for these factors. Generic capacity factors (0.2 for solar PV and 0.3 for wind) are used to convert from PWh to GW.

18 The steps for the resource assessments are: (1) identification of areas to meet baseline technical, environmental, economic and social suitability criteria for renewable energy development; and (2) estimation of potential generation based on resource assessment thresholds and other land-use factors. The details can be found in (IRENA and LBNL, 2015a).

19 While the costs of renewables have declined since this study, land-use restrictions, solar irradiation and wind speeds do not change significantly over the years. The initial set of zones identified would still be valid today. In the specific case of South Africa, where the zones were formulated from Renewable Energy Deployment Zones (REDZs) identified by the CSIR, more REDZs have been identified recently to provide power in areas where coal power stations would be decommissioned and where new renewables can make use of existing grid and road infrastructure (CSIR, 2019). While IRENA has not considered these REDZs specifically in its analysis, additional renewable options beyond existing zones with slightly lower capacity factors are considered as generic options to be explored.

20 A measure of the contribution of the generation profile to meeting peak demand (IRENA and LBNL, 2015a).

Figure 3-3: Schematic of how zones are derived and used for further analysis



Among all the zones originally identified in the MapRE analysis, further screening was conducted to identify investment options for comprehensive investigation in the subsequent SPLAT modelling analysis. This subset collectively corresponds to 161 GW for solar PV and 124 GW for wind. These numbers were set from IRENA's earlier power pool studies that assessed the investment potential for the continent and some additional margin was added. The zones were selected by their rankings upon applying multi-criteria analysis, while making sure that a number of zones are identified in each country. Zones in some countries would therefore not qualify in other countries. As a result, 186 solar PV zones across 19 countries and 149 wind zones across 16 countries were identified. In total, 335 zones representing a total of 285 GW of potential solar PV and wind capacity were identified (Table 3-1). A list of all assessed zones and their attributes are provided in the Appendix 7.6.

Table 3-1: Collective generation potentials (MW) from the screened zones[21]

Country	Solar PV - Utility	Wind
Angola	2 669	
Botswana	1 388	1 440
Burundi	299	
DRC	4 478	1 284
Djibouti	1 270	824
Egypt	63 806	58 775
Eswatini	542	327
Ethiopia	16 491	5 929
Kenya	3 005	4 970
Lesotho	312	336
Malawi	1 254	1 001
Mozambique	3 517	2 259
Namibia	2 088	1 373
Rwanda	330	
South Africa	38 006	26 175
Sudan	2 160	5 778
Tanzania	8 744	6 005
Uganda	1 711	1 228
Zambia	4 125	3 067
Zimbabwe	4 337	2 884
Grand Total	**160 530**	**123 654**

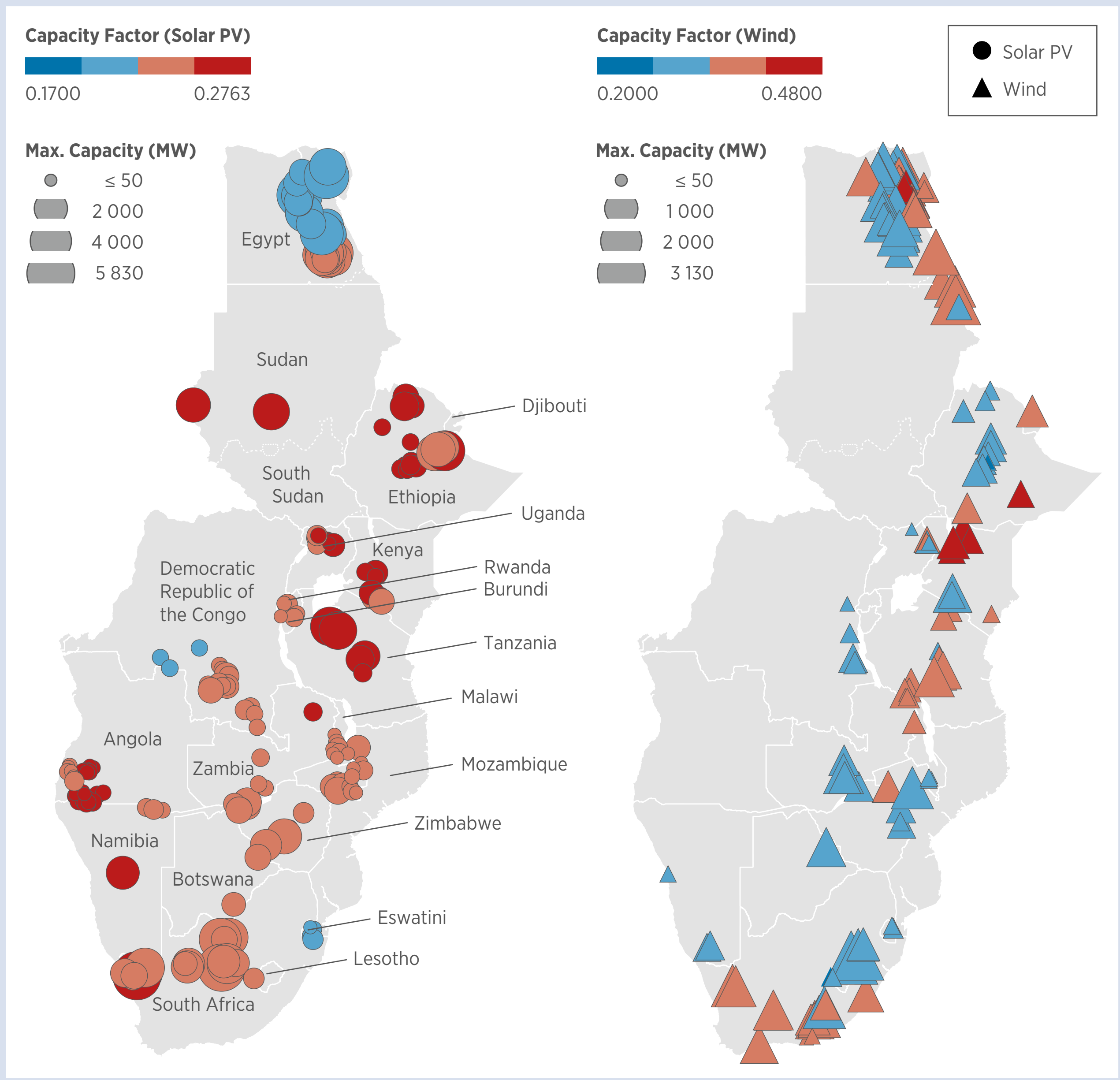
Figure 3-4 shows the location of 335 zones for solar PV and wind, and their corresponding capacity factor estimations.[22] The markers' sizes are proportional to the maximum capacities of the zones and are derived from land area (IRENA and LBNL, 2015b, 2015c).

Beyond these location-specific zones, resources with slightly lower capacity factors are also considered in the model. The capacity factors of these additional options are 20% lower than the lowest capacity factors of the zones.

21 Only onshore wind is considered, as it accounts for the majority of the generating fleet in the region.

22 The capacity factor is the ratio of actual electrical energy output over a given period of time to the rated peak power output over the same period. A plant with a higher capacity factor produces more energy electricity per unit of capacity compared to a plant with a lower capacity factor.

Figure 3-4: Identified solar PV and wind zones.



Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

It is observed that the solar PV zones with the highest capacity factors can be found in Angola, Ethiopia, Uganda, Tanzania, Zambia and Zimbabwe. The wind zones with the highest capacity factors can be found in Egypt and Kenya. The mean capacity factors for solar PV and wind generation are generally favourable across the region – at 0.24 and 0.34, respectively – compared to global averages (0.18 and 0.36), (IRENA, 2020b). A zone's capacity factor is inversely proportional to its LCOE, which is an indication of the tariff an asset requires to break even. Zones with high capacity factors are likely to be deployed first as they can produce, at lower cost, more output per unit of capacity, provided that the profile matches the load of the country.[23]

23 Other necessary factors will also include land availability and adequate power evacuation capacity.

3.3 Hydropower

Figure 3-5 illustrates the estimated upper MW bound of dams and run-of-river plants in the region, according to their maximum capacities in the EAPP and SAPP master plans (EAPP, 2014; SAPP, 2017); however, their theoretical potential is higher.

In Southern and East Africa, key rivers are the Congo, Nile and Zambezi. At 41 000 m^3/s, the Congo is second only to the Amazon in terms of run-off. Along this river in the DRC, three cascade hydropower stations are being considered (Pioka, Inga and Matadi). In addition, there are the Kwanza and Rufiji rivers, which flow through Angola and Tanzania, respectively (GEIDCO, 2018).

The circles on the map indicate the estimated hydropower generation capacity potential at the respective locations indicated, including sites with existing capacity. It is observed that hydropower plants with very large capacities are possible in the DRC and Ethiopia.[24]

Whilst the projects identified in the master plans mainly reflect grid-connected projects, some ACEC countries also have substantial mini- and micro-hydro potentials that are not considered here.

In addition, pumped storage plants with a total capacity of 2.9 GW are currently in operation in South Africa.[25] An additional 2 400 MW in Egypt and 1 200 MW in Lesotho[26] are expected to be operational from 2024 and 2025 respectively. The hydro resources in the Great Lakes Region[27] also has potential to be used for pumped storage, which may be considered in future work.

24 They include, for example, the Grand Inga project in DRC with a maximum capacity of 20 GW, as well as the Gibel IV and V, and Renaissance projects in Ethiopia, with capacities of 3.6 GW and 6.4 GW, respectively.

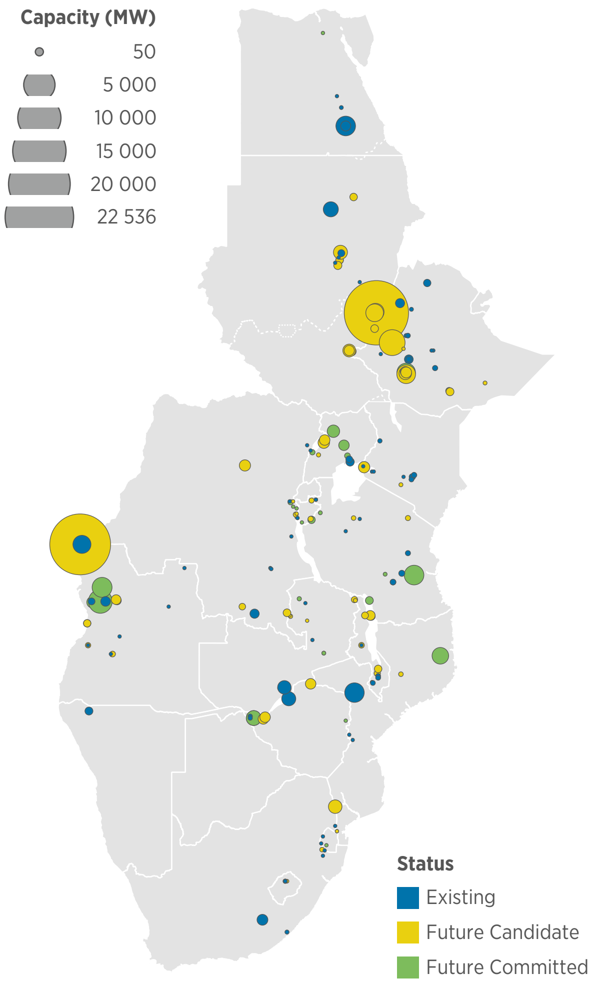
25 Ingula (1 332 MW), Drakensberg (1 000 MW), Palmiet (400 MW) and Steenbras (180 MW).

26 Attaqa, Egypt (2 400 MW) and Kobong Dam, Lesotho (1 200 MW).

27 Burundi, DRC, Kenya, Malawi, Rwanda, Tanzania and Uganda.

Figure 3-5: Potential capacity (MW) for electricity production from new and existent hydropower technology

Country	Large Hydropower	Small Hydropower
Angola	9 763	
Burundi	331	
DRC	23 990	71
Egypt	2 800	32
Eswatini	192	
Ethiopia	46 831	11
Kenya	1 573	11
Lesotho	270	
Malawi	1 601	9
Mozambique	6 134	
Namibia	647	
Tanzania	5 242	24
Rwanda	266	
South Africa	644	94
South Sudan	2 172	
Sudan	5 022	10
Uganda	4 067	
Zambia	5 720	149
Zimbabwe	3 480	
Grand Total	**120 745**	**410**



Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

3.4 Biomass – wood and sugarcane

Two IRENA studies served as data sources for the resource availability in GWh of wood biomass (IRENA, 2014a) and rain-fed sugarcane (IRENA, 2014b). Assuming 50% of that energy can be retrieved as power through a plant, a conservative estimate of the capacity for biomass is derived as a proxy for national resource availability. The potential for Mozambique was taken from the *Mozambique renewable energy atlas* (Gesto Energia, 2013). Particularly high theoretical capacity for power production (above 3 GW) from biomass can be observed in the DRC, Uganda and Ethiopia (in decreasing order).

The ecological impact of using biomass is considered by restricting potential areas to those which are not protected. Sustainable forestry and co-generation are also important for future estimates of wood and sugarcane potential.

Table 3-2: Summary table of biomass (rain-fed sugarcane and bagasse) potential (MW) by country

Country	Biomass
Angola	2 766
Botswana	20
Burundi	308
DRC	12 304
Djibouti	3
Egypt	2 636
Eswatini	95
Ethiopia	3 981
Kenya	1 931
Lesotho	52
Malawi	442
Mozambique	2 181
Namibia	21
Tanzania	2 138
Rwanda	211
South Africa	1 268
Sudan	2 066
Uganda	4 321
Zambia	1 413
Zimbabwe	328
Grand Total	**38 484**

3.5 Concentrated solar power (CSP)

To deploy concentrated solar power technology on a large scale, high amounts of direct radiation are required, as opposed to photovoltaics (PV) which can use diffuse radiation. In the region, high direct normal irradiance (DNI), (6.7–7.2 kWh/m^2-day) is available in Botswana, eastern Ethiopia, Namibia, western Sudan and South Africa (IRENA and LBNL, 2015a).

While CSP technology offers storage capability and dispatchability, and the cost of deploying CSP technology is falling, the market for CSP is still relatively thin. CSP has yet to reach the same level of price competitiveness as solar PV and wind technologies.[28] CSP plants are currently in operation in Egypt[29] and South Africa[30] with total capacities of 140 MW and 600 MW, respectively. An additional 1 050 MW[31] in Egypt and 100 MW[32] in South Africa are expected to be commissioned in the near future. An additional margin of 1 050 MW is included in Egypt, as the potential in the country is considered to be high. This report makes no further assessment of the potential of CSP beyond existing and currently identified projects.

3.6 Geothermal

Geothermal, as a form of energy, is sustainable and can be used for baseload generation due to its dispatchability. It can also be used as a load-following technology. Initiatives such as the Geothermal Risk Mitigation Facility were established by the African Union Commission to support feasibility studies for potential geothermal projects.

Geothermal resources are largely present in East Africa along the great rift valley. About 16 GW of capacity is identified as plausible, with 10 GW from Kenya. As of 2019, 830 MW is deployed (IRENA, 2020a).

28 According to IRENA's recent report on renewable power generation cost (IRENA, 2020b), the 2019 global weighted average LCOE for CSP is 0.182 USD/kWh – more than double that of solar PV (0.068 USD/kWh). Global average investment cost for CSP (5 774 USD/kW) is currently significantly higher than that of other VRE generation technologies (995 USD/KW for solar PV and 1 473 USD/KW for onshore wind).

29 Kuriemat (140 MW), (EAPP, 2014).

30 KaXu Solar 1, Ilanga CSP 1, Xina Solar 1, Kathu Solar Park, Redstone CSP at 100 MW each; Khi Solar 1, Bokspoort at 50 MW each (SAPP, 2017).

31 Including Kom Ombo/Aswan (100 MW) and West Nile (700 MW); a 250 MW plant was also announced in late 2019.

32 Eskom Upongton CSP (100 MW), (EAPP, 2014).

PART II:

PROSPECTS FOR ACEC POWER SYSTEM EVOLUTION THROUGH 2040

The potential of renewables, as defined in the previous section, refers to the achievable generation capacity given physical and land-use constraints, and the energy content of the resource. It has yet to account for the competition of an energy source with other sources or the economic costs associated with power production. It offers an upper limit to what is possible, instead of the achievable generation in a dynamic power system.

Part II of the report comprises two chapters which analyse the prospects for the ACEC's power system. It explains methodologies, drivers and assessments that are important to the long-term outlook for power systems in the region and under different scenarios.

Chapter 4 introduces the key drivers in the evolution of the power system; it also explains the methodology and the System Planning Test (SPLAT) model, as well as possible future scenarios.

Chapter 5 presents an in-depth analysis of long-term prospects in terms of overall supply mix; rich insights are generated by evaluating the power system's characteristics under different scenarios.

KEY METHODOLOGIES

4

In order to assess the possible future evolutions of the power systems in the region and the roles of renewables in future power systems, we deployed a capacity expansion modelling method, combined with the zoning analysis.

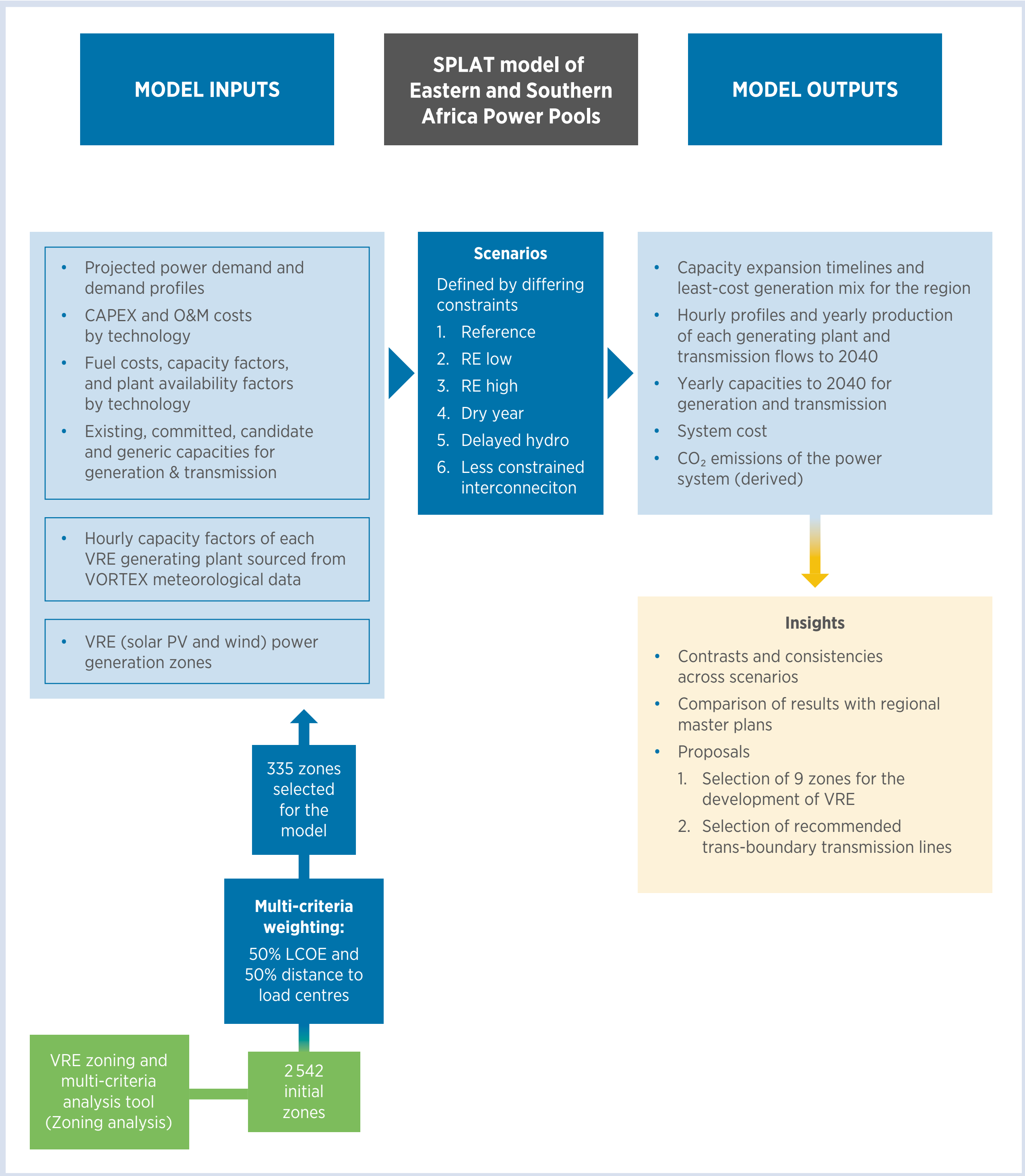
As discussed in Section 3.2, a subset of available resources is analysed as project-sized "zones" in areas where good resources concentrate, so that energy planners can translate the vast potential on the continent into more tangible investment options.

In addition to RE potential, non-RE options are also considered. The options' deployment within a given time frame is primarily determined by the overall power demand in a country, generation costs relative to other sources, operational characteristics and trade among countries. Such an assessment is enabled by capacity expansion modelling tools. At IRENA, the SPLAT model is deployed for this purpose. This chapter explains the assumptions underlying this assessment.

4.1 SPLAT model – IRENA's capacity expansion modelling tool for Africa

The SPLAT model is a capacity expansion modelling tool that IRENA developed for 47 African countries. It is built on the Model for Energy Supply System Alternatives and their General Environmental Impacts (MESSAGE) software developed by the International Institute for Applied Systems Analysis (IIASA) and adapted by the International Atomic Energy Agency (IAEA) for national energy planning purposes (International Atomic Energy Agency, 2017). The model uses a system cost-minimisation algorithm and can run in single-country mode (where international electricity trade is defined exogenously as model input) or multi-country mode (where trade is treated endogenously as part of the cost-minimization). For this analysis, we run the multi-country mode, so generation and transboundary transmission investments for 21 ACEC countries (out of 47 African countries) are optimised endogenously by the model.

Figure 4-1: Schematic of the methodology used for the analysis in this report



Each country's hourly demand profile was exogenously defined. The model then assessed how the demand can be met cost optimally with dispatch, trade and capacity buildout. The supply options chosen are subject to various operational constraints and, for some scenarios, VRE penetration targets. The model is calibrated to replicate existing power systems (generation units and transboundary transmission lines) for the initial years from 2015. It is then used to choose an optimal mix from a catalogue of future technology options to meet future demand.

Figure 4-1 is a schematic of the analysis, showing the process, inputs, outputs and the key types of insights facilitated. The assumptions in the model can reflect varying expectations for the future, such as a more ambitious renewables policy in ACEC countries or higher-than-expected levels of power trade. The varying assumptions can lead to changes in the least-cost power supply mix for the region, with implications for total system costs,[33] CO_2 emissions associated with power generation, etc.

Box 4-1: SPLAT model for the region

Compared to the SPLAT models IRENA developed for other African countries in past studies, the model for the region (SPLAT-ACEC) has higher temporal and geospatial resolutions. In addition, by integrating the zoning analysis, the SPLAT-ACEC model outputs also suggest the geographical locations of additional renewable capacity that should be deployed from the point of view of cost optimisation. The zoning analysis (Section 3.2) identifies potential suitable locations for cost-effective utility-scale VRE deployment; these are used to determine the estimated maximum capacity for VRE deployment in each country. As inputs to the SPLAT-ACEC model, they are considered as candidate projects in the least-cost optimisation under different scenarios. In addition to zones, the model also identifies the capacity timelines for other candidate and generic projects of solar PV, wind, other generation technologies and transmission projects. Outputs of the model include a simplified generation profile for each producing plant for the representative time slices, trade flows between interconnected countries, and yearly capacity expansions to 2040.

33 Total system cost in this analysis includes the costs associated with production (variable operating and maintenance costs, fuel costs) and investments in generation and transmission and capacities (CAPEX, fixed operation and maintenance costs).

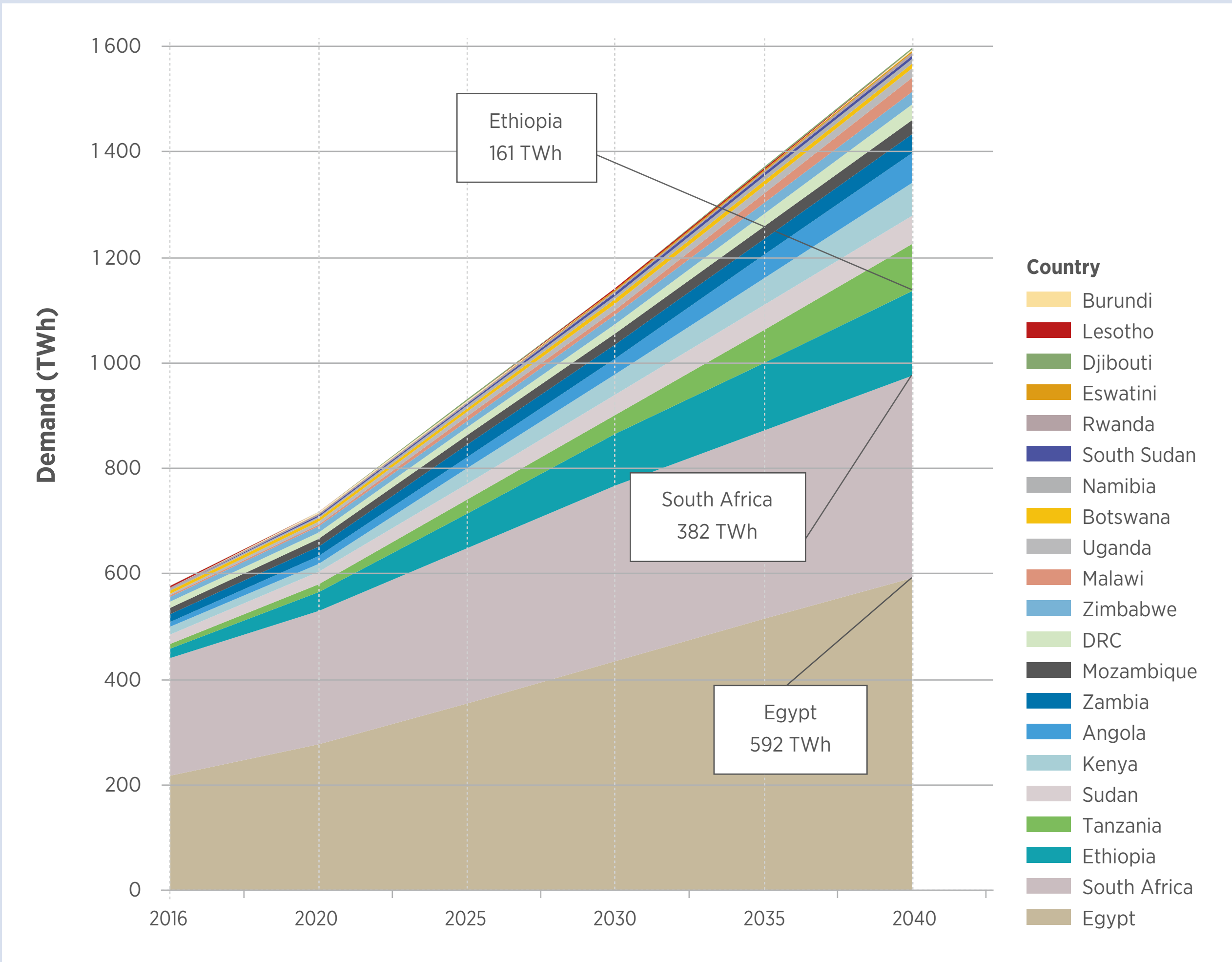
4.2 Main assumptions

4.2.1 Power demand

The electricity demand projections in this report were derived from the reference cases presented in the latest EAPP and SAPP master plans[34] (Section 2.1), with revisions for a few countries. The underlying assumptions of the demand projections for these countries can be found in their respective references. The revisions are outlined in Table 4-1. Sent-out demand, as opposed to final demand, is demand prior to distribution losses. As the SPLAT-ACEC model optimises supply directly according to sent-out demand, distribution losses do not need to be added additionally.

Figure 4-2 shows the projected electricity demand for the region from 2016 to 2040. The year-on-year projections for each country can be found in Appendix 7.2.1. By 2040, Egypt is expected to have the largest electricity demand (592 TWh) in the region, followed by South Africa (383 TWh) and Ethiopia (161 TWh), (EAPP, 2014; SAPP, 2017).

Figure 4-2: Electricity demand projections from 2016 to 2040, by country (TWh)



34 The modelling analysis extensively uses data from the EAPP and SAPP master plans for formulating assumptions on demand, costs and exogenous capacities. As the master plans were published in 2014 and 2017, respectively, demand projections to 2019 can vary from real historic observations. For the DRC and Tanzania, which are in both the EAPP and the SAPP, the demand figures are taken from the SAPP master plan, as the source is more recent.

Table 4-1: Alternative sources for demand projections in selected countries

Country	Source
Egypt	With the EAPP master plan
Ethiopia	SAPP-EAPP Transmission Impact Study (Aurecon, 2018)
Kenya	Vision scenario from Development of a Power Generation and Transmission Master Plan, Kenya (Lahmeyer International GmBH, 2016)
Uganda	Communication with Uganda Electricity Transmission Company Limited (UETCL, 2018)
Zambia	SAPP-EAPP Transmission Impact Study (Aurecon, 2018, p. 20)

4.2.2 Seasonal profiles

4.2.2.1 Definition of seasons and time profiles

In the model, the years are characterised by load profiles for the various seasons and parts of the day to capture the key features of electricity demand patterns. A year is divided into three seasons, namely season 1) January–April; season 2) May–August; and season 3) September–December. Each season is represented with an average day, characterised by ten blocks per day (including an 8:00 p.m. "peak"), resulting in a total of 30 "time slices" per year. The hours are all adjusted to the South African Standard Time (SAST) zone. Figure 4-3 shows the mapping between the hour of a day and the corresponding time slice.

Figure 4-3: Time slices used to represent the 24 hours in a day (at SAST)

Hour of day	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Timeslice	1	1	1	1	1	1	2	3	3	4	4	5	5	6	6	7	7	7	8	9	9	10	10	10

4.2.2.2 Load profiles

Load profiles are collected for 13 countries (Botswana, Egypt, Eswatini, Ethiopia, Kenya, Mozambique, Namibia, South Africa, Sudan, Tanzania, Uganda, Zambia and Zimbabwe) through the MapRE project and estimated for those countries for which profiles are not available. Table 4-2 shows the sources of load profiles for these countries. All profiles in local time are then shifted to SAST.

In this analysis, the daily profiles unique to the countries are scaled to match the unique annual sent-out demand values of the respective country. Load profiles are then averaged to produce 10 time slices per day across the three seasons. Figure 4-4 presents the profiles of various countries with different shapes, alongside an averaged example of South Africa's pattern for season 2 (May–August), scaled for different years. Across all countries, peak demand hours occur in the evenings, between 6:00 p.m. and 9:00 p.m. local time.

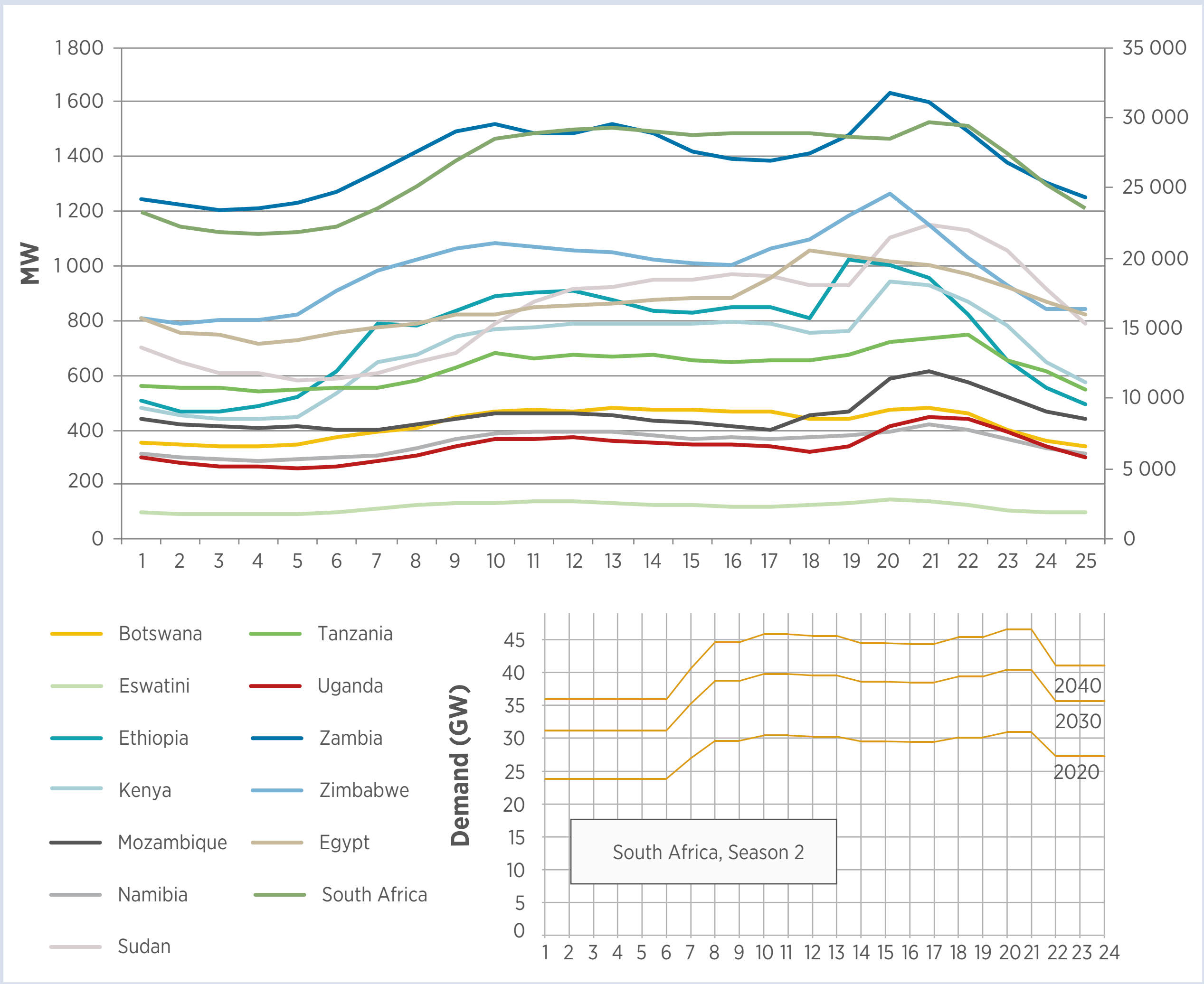
Table 4-2: Sources of load profiles for countries with limited data

Country	Source country of proxied profile
Angola	Kenya[35]
Burundi	Uganda
DRC	Uganda
Djibouti	Egypt
Lesotho	Eswatini
Malawi	Mozambique
Rwanda	Uganda
South Sudan	Sudan

In reality, daily demand profiles change over the years due to changing consumption habits and electricity use by sector. In the model, the shape of the normalised profile is constant through 2040 due to the lack of detailed analysis. The profile is also exogenous and thus does not account for the dynamics of new technological innovations such as demand-side response strategies. There was also a lack of good quality data in some countries. Future work in partnership with governments and utilities in the region could assess the possible future development of load-profiles that reflect socio-economic structural changes in respective countries.

35 The patterns for Angola and Kenya are assumed to be the same in local time, that is, peak demand occurs in the same hour of the day in the local time of both Angola and Kenya.

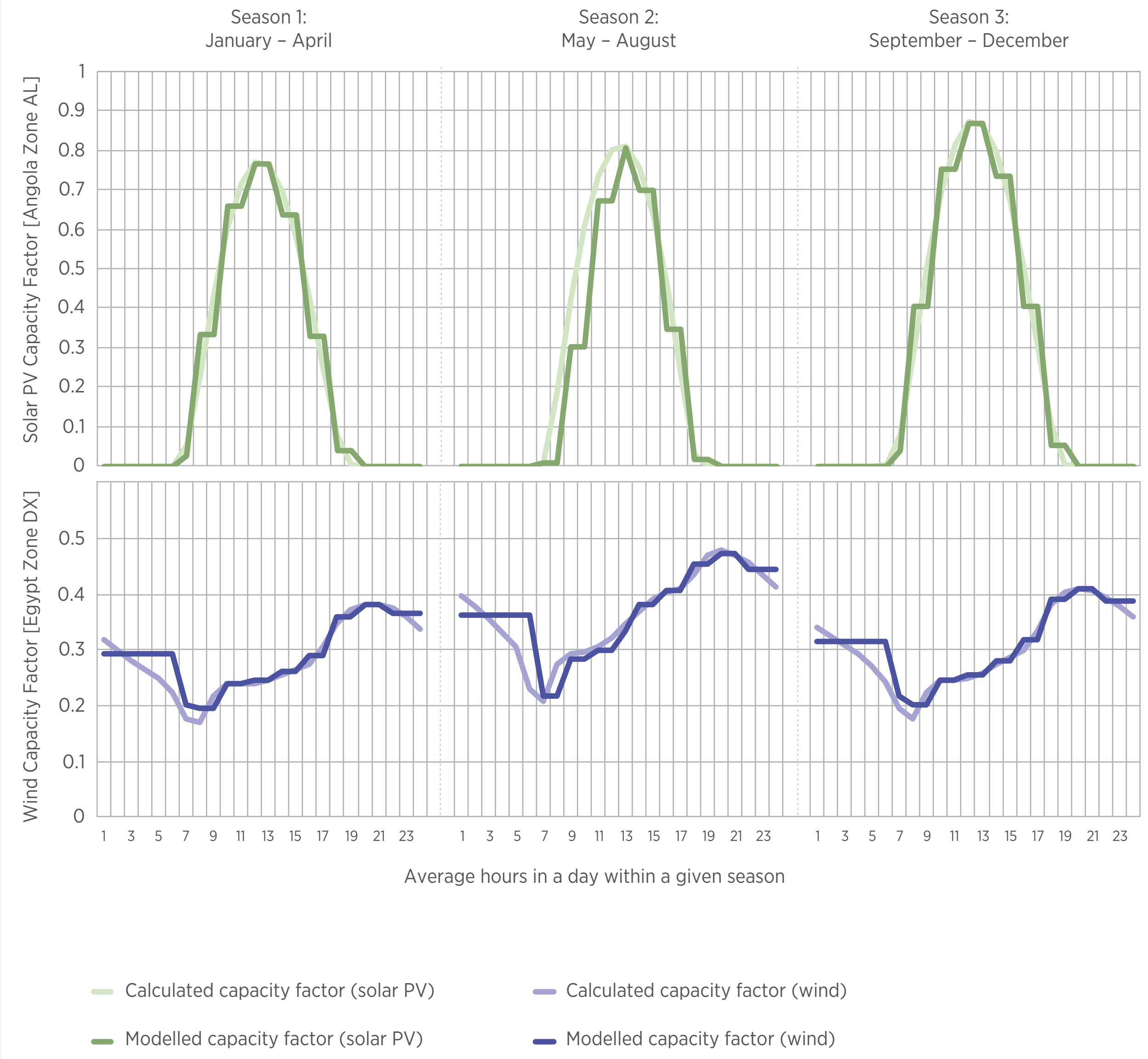
Figure 4-4: Hourly demand profiles for a day in January (left) and scaled 10-time slice representation of demand profile for South Africa in season 2, in local time



4.2.2.3 VRE profiles

For this report, hourly capacity factors were derived based on meteorological data and averaged to produce daily profiles representing each of the three seasons.[36] Within the model, the capacity factor patterns determine the hourly generation of solar and wind. Solar PV, for example, is not able to produce at night, when the capacity factor is zero, while wind cannot provide beyond its capacity factor. The capacity factor profiles are specific to each zone. The method is outlined in detail in Appendix 7.1. Figure 4-5 shows two such examples of capacity factor profiles for solar PV (example of a zone in Angola) and wind (example of a zone in Egypt). The meteorological data used were reanalysis data from Vortex (Vortex, n.d.).

Figure 4-5: Examples of average capacity factor profiles for solar PV and wind for the three seasons



36 *The three seasons are: January–April (season 1); May–August (season 2); and September–December (season 3).*

The project zones' capacity factor profiles were derived by averaging the daily profiles of each of the three seasons modelled. This smooths out intra-seasonal and intraday variability, especially for wind. As a result, the model can underestimate the fluctuations of VRE production, thereby also understating the firm capacities required of synchronous generators. The modelled results may, therefore, favour renewable technologies.

Seasonal availability for run-of-river plants is not represented as these plants are relatively small in the model. Hydropower dams and biomass are both assumed to be dispatchable. For these technologies, there are dry periods that can limit generation, yearly availabilities are thus used to constrain generation. Non-technical factors such as water legislation is not within the scope of this report. The model also has perfect foresight, having implications on the modelling of storage and unforeseen droughts. It is understood that hydro seasonality can influence trade (Sridharan et al., 2019), which can be built upon in future studies.

4.2.3 Generation and transmission capacity

Estimates for the potential of non-VRE renewable resources are proxied using the maximum potential capacities (MW) possible by 2040,[37] including existing capacities. The resource quality of each renewable technology is elaborated in the following sections.

For clarification of terminology, Box 4-2 provides an overview of the categories that describe the status of the generation capacity and interconnection projects included in the model. The status of each project is consistent with that used in the master plans. Details on the locations, capacities and build years of the plants in each category can be found in the Appendix.

Box 4-2: Categories to describe the status of generation and transmission capacity projects

- **Existing** capacities are power generating plants or transmission lines that have already been built.
- **Committed** projects are site-specific. They are, as of 2015, under construction or commissioned to be built at fixed dates, having already reached financial closure and received all necessary approvals. These projects are included as part of the known future capacity mix.
- **Candidate** capacities are site-specific projects still under consideration as investment options. They may be built in the future and have an "earliest online" year associated with them.
- **Zones** are areas deemed to be suitable for large-scale renewables deployment, selected through a multicriteria analysis and described in detail in Section 3.2. Like candidate projects, they may be built to an optimal size in the future. They also have an "earliest online" year associated with them.
- **Generic** capacities are additional capacities without specific reference to any unit size or location. They may be required depending on demand. The earliest years in which generic capacities can come online come after those of candidate projects for each technology type.

37 In the model described in Section 4.1, these estimates are used as inputs for the maximum capacities that can be built by 2040.

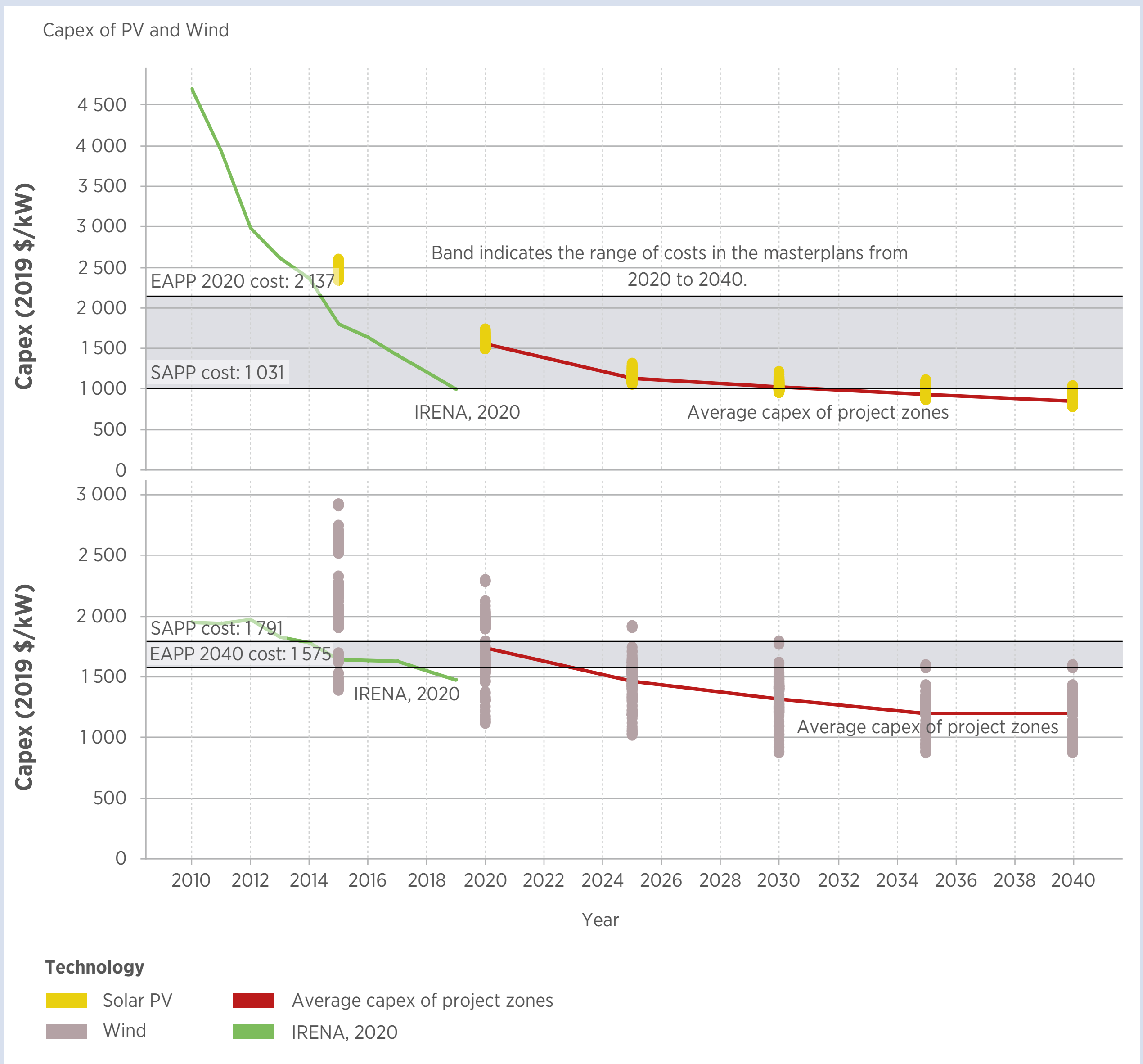
4.2.4 Cost assumptions

This section discusses costs as one of the key drivers for future power generation and renewables deployment. A comprehensive table of costs – both in terms of capital, and fixed operation and maintenance (FOM) – of all technologies can be found in Appendix section 7.2.2.

4.2.4.1 Capital costs

A discount rate of 10% is used for all costs. Figure 4-6 shows the global weighted average CAPEX observed between 2010 and 2018, alongside the estimated past and future CAPEX of all the zones identified, indicated by the yellow (solar PV) and green (wind) points. The former is derived from an IRENA database of renewable projects and is indicative of the CAPEX of the technologies. Grey bands show the ranges of capital costs in

Figure 4-6: CAPEX (2018 USD/kW) of solar PV (top) and wind (bottom) projects in recent years (2010–2018) based on (IRENA, 2020b), and projected CAPEX of modelled zones to 2040



the master plans.[38] The capital costs of VRE technologies have been decreasing in recent years (IRENA, 2020b). Between 2010 and 2019, the global weighted average capital cost of solar PV has reduced by 78%, while that of onshore wind has decreased by 24%. Following this trend, the capital costs of solar PV and wind projects are expected to continue to fall.

The capital cost of project zones includes transmission and infrastructure-related expenses in addition to the generation plant investment. However, these additional costs are relatively small, at approximately 2% of total costs, in part because the zoning process already precludes zones that are far from load centres and, therefore, existing transmission lines. While the historical CAPEX data are from real projects and often the most economically viable and cost competitive, the future CAPEX of the zones are for potential projects which may or may not be built subject to their effectiveness in minimising total system cost. The generic costs used for modelling the technologies can be found in Section 7.2.2.

For other technologies, 161 out of 171 candidate projects have CAPEX and fixed operation and maintenance (FOM) cost data in the SAPP or EAPP master plans and their specific costs from the master plans are used. Hydropower is particularly capital intensive among planned projects. The average CAPEX of a dam is USD 3 582/kW (median is USD 3 150/kW) and can be as high as USD 12 610/kW (Wabi Shebele in Ethiopia). For run-of-river (ROR), the average CAPEX of all candidates is USD 3 467/kW.

Otherwise, if project-specific costs are not available, such as for ten candidate projects and all of the generic options, the CAPEX values listed in Table 4-3 are used (SAPP, 2017), and FOM is assumed to be 3% of the CAPEX. The investment costs modelled for solar PV and wind reach the same range as that of combined-cycle gas turbines (CCGTs) by 2025 and in the late 2030s, respectively. Retrofitting fossil fuel and nuclear generation plants can make the plants more flexible and can be considered in future extensions to this report.

Table 4-3: Reference CAPEX of technologies in the model (2015 USD), if project-specific costs are not available

Technology	CAPEX (USD/kW)
Biomass	2 500
Coal	3 739
Nuclear	6 137
Diesel engine	1 086
Combined cycle gas turbine (CCGT)	1 014
Open cycle gas turbine (OCGT)	795
Gas engine	1 086
Geothermal	4 000
HFO engine	1 086
Hydro small	3 000
Hydro ROR	2 500
Hydro dam	3 000

Note: the costs are constant throughout the study period.

38 There is no learning rate indicated in the SAPP master plan. In the EAPP master plan, costs in 2020-2034 are constant, followed by a step reduction to a lower cost in 2035-2040.

4.2.4.2 Generation costs

For conventional technologies, generation costs are tethered to the commodity prices of the fuels they use. The projected prices used in the model are based on the SAPP master plan (SAPP, 2017) and are adapted from international prices. Fuel prices for coal, gas and oil are expected to increase over the coming years. With relatively stable capital costs and increasing fuel costs, the costs of fossil fuel-fired generation technologies are increasingly undercut by renewable technologies.

In South Africa, for example, over the last 20 years, underlying coal production costs have risen significantly, rendering coal increasingly uncompetitive against other fuel sources. At the same time, the deployment costs of renewable energy have decreased by over 50% for both solar PV and onshore wind since 2011 (ESI Africa, 2019).

Table 4-4: Fuel price assumptions (2017 USD/GJ)

Fuel	2015	2030	2040
Coal (imported)	3.1	3.4	3.7
Coal (domestic)	2.5–3.1	2.7–3.4	3.0–3.7
Diesel	10.7	19.5	21.8
HFO	7.3	13.3	14.9
Natural gas (LNG netback)	9.1	11.5	13.7
Natural gas (domestic)	6.6	9.0	11.2
Uranium	1.4	1.4	1.4

Source: (SAPP, 2017).

The variability of renewables production can result in conventional generators incurring higher ramping costs. However, the ramping costs of conventional generators are not considered explicitly in the SPLAT model. As the modelling analysis attempts to understand the economic cost of the deployment of technologies, the fuel subsidies in place in some countries are not considered, as they are not reflective of the economic cost.

The variable operation and maintenance costs (VOM) of candidate projects are used if available in the EAPP master plan (Table 4-5). Otherwise, they are assumed to be accounted for in the fixed costs implicitly. VOM costs do not include fuel costs.

For hydropower, of the 194 existing, committed and candidate hydro projects modelled, a variable operation and maintenance cost of USD 3.3/MWh is estimated for 87 sites in eight East African countries (Burundi, Egypt, Ethiopia, Kenya, Rwanda, South Sudan, Sudan and Uganda) based on data used by the EAPP master plan. For biomass, out of the 19 existing, committed and candidate biomass projects modelled, a variable cost of USD 3.74/MWh is assumed for 11 of the bagasse projects, in Ethiopia, Kenya and Uganda. This is based on the EAPP master plan's reported variable costs for bagasse plants (EAPP, 2014). Of all the technologies, solar PV has the lowest VOM cost at 0.2 USD/MWh.

Table 4-5: Variable operating and maintenance cost (VOM) in the EAPP, constant throughout the study period

Technology	VOM (USD/MWh)
Biomass	3.7
CCGT	2.1
Coal	3.7
Diesel engine	1.8
Diesel turbine	1.7–2.1
Geothermal	3.1
HFO (heavy fuel oil) Engine	1.8
HFO turbine	3.7
Hydro dam	3.3
Hydro ROR	3.3
Hydro small	3.3
OCGT	1.7–3.7
Solar PV – utility	0.2
Solar thermal with storage	3.7
Wind	3.7

4.2.4.3 Transmission costs

The costs of candidate interconnectors are specific to the connection themselves;[39] they range from USD 20 million for a 300 MW, 74 km transmission line between Mozambique and Zambia to USD 4 737 million for a 2 500 MW/7 207 km of lines between the DRC and South Africa. The data is mostly from the SAPP–EAPP Interconnection Impact Studies in 2018 (Aurecon, 2018). The DRC–RSA line, for example, will span several countries and is thus more expensive. Candidate interconnectors, their types, investment costs and sources may be found in Appendix 7.8.

Aside from the master plans, there are few sources for comprehensive documentation of the specifications, costs and plans of transboundary transmission lines in Africa. Thus, for generic interconnectors, costs are simplified to be uniform for all lines, even though in reality they depend on type, length, geographical location and voltage specifications. Due to the lack of data, their CAPEX was estimated to be USD 800/kW, independent of distance. It should be noted that some studies employ cost estimates based on distance, but this is not being incorporated in the SPLAT model structure (Taliotis et al., 2016).

4.2.5 Constraints related to system and unit operation

Reserve margins[40] of 10% by 2040 are set to ensure the reliability of the system for each country. As interconnector capacity also counts towards the reserve margin, they may be built when there is a high deployment of VRE to fulfil this constraint.

39 Power is modelled to be able to flow in both directions along an interconnector. The model does not distinguish between flows on HVDC or HVAC lines.

40 Dispatchable technologies and transmission lines can contribute to reserve requirements. Solar PV and wind do not contribute to reserve requirements (they have zero capacity credit). Non-zero capacity credits would support greater buildout of these technologies in the modelling. Therefore, the exclusion of solar PV and wind as contributors to reserve requirements was a conservative measure to investigate the lower bounds of technical and economic potential of solar PV and wind zones. Detailed country-specific analyses of variable renewable production are recommended to improve upon these simplified assumptions.

In reality, thermal plants such as coal and biomass are not able to change their production easily from one hour to the next. The ramping constraints of these technologies were represented by de-rating the plants by an availability factor). ROR hydropower plants are modelled as non-dispatchable, with capacity de-rated by (1-availability). While the seasonal generation profiles of ROR sites may warrant further investigation in more detailed analyses, they have not been incorporated in this report. Hydropower plants with dams are modelled as dispatchable to reflect dams' more flexible operation.

4.3 Six scenarios modelled

As outlined in Section 3.1, the assumptions in the SPLAT-ACEC model can be altered to reflect varying expectations or objectives for the future. All scenarios seek to minimise the total system cost.

The Reference scenario (REF) seeks to portray a realistic possibility for the evolution of the power system, with unconstrained penetration of renewables, i.e. without targets or limits to VRE penetration. In line with this report's objectives, IRENA also formulated and modelled five alternative scenarios in addition to the Reference scenario, to explore the implications of the following factors:

1. varying degrees of variable renewable energy (VRE) deployment;

2. changes in the availability of hydro resources; and

3. the degree of regional integration of power systems.

The five alternative scenarios were created based on the following assumptions: a high level of VRE deployment (forced to achieve higher penetration of VRE); a low level of VRE deployment (forced to limit the level of VRE penetration at a lower level); reduced hydropower availability due to drier climatic conditions; delayed construction of hydropower plants; and greater ease in the building of interconnector lines. The model does not aim to forecast the future but to explore different possibilities and their implications. All the scenarios' outcomes result from decisions based on assumed cost developments for fuels and technologies.

Existing capacities (existing projects), proposed capacity expansion projects (candidate projects) and planned projects that have reached maturity in terms of bankability (committed projects) and have been identified in the SAPP and EAPP master plans are all included in the scenarios according to their definitions (see Appendix Section 7.7). Capacities of existing and committed projects are forced in the solution. As much as possible, recent capacity developments since the publication of these master plans up to 2018 were also cross-checked and included. The generation technologies featured in all the scenarios include conventional options such as coal and natural gas, as well as renewable energy technologies.

Further details regarding the assumptions and parameters underlying the Reference scenario are provided in Section 7.2 of the Appendix. The following sections describe the key characteristics of the different scenarios.

4.3.1 Reference Scenario (REF)

The Reference Scenario (also referred to as the 'base case') serves as a baseline for the alternative scenarios. The Reference scenario depicts the trajectory of the power supply mix to 2040 based on the system cost-optimisation methodology of the SPLAT-ACEC model and reference assumptions of this report (see Section 7.2 of the Appendix). The scenario is unconstrained in that it neither stipulates any specific renewable energy penetration in the power system of ACEC countries nor any CO_2 reduction targets. Interconnector expansion in the scenario is limited to currently identified projects, some of which are already committed. The limit is placed on interconnector expansions as the planning process often requires long lead times. This is different from what is conventionally known as a 'business-as-usual' (BAU) scenario, as it features investment decisions which endogenously take place within the model to optimise system cost, while a BAU scenario does not consider these options. As outlined below, solar PV and wind account for 36% of regional power production in the base case by 2040.

4.3.2 Scenarios for different levels of penetration of VRE in the regional generation mix

Based on the Reference scenario, which foresees 36% VRE penetration in 2040, two additional scenarios are modelled to have higher and lower VRE penetrations of approximately 15% around this outcome, to demonstrate how the power system would manage these targets and constraints. The scenarios are:

(i) Limited penetration of VRE to 20% (VRELim)
This scenario aims to show the implications of limiting the pace of solar PV and wind deployment in the region, relative to the REF case. The scenario represents cases where there is a lack of ability to implement projects due to non-cost reasons. The scenario imposes a limit on the combined solar PV and wind generation in total regional generation. The restrictions limit VRE penetration to 5% in 2020, 10% in 2030 and 20% in 2040. The limitation only acts on the overall production, aggregated over the entire region. All other assumptions are equivalent to the Reference scenario.

(ii) 50% share of variable renewables in the regional generation mix in 2040 (VREHigh)
This scenario serves to investigate the outcome and additional investments needed when there is a more ambitious deployment target for solar PV and wind relative to the Reference scenario. In this scenario, 50% is set for regional power generation from utility-scale solar PV and onshore wind in 2040.[41] All other assumptions are equivalent to the reference scenario.

4.3.3 Dry-year (HyDry) and Delayed hydro (HyDel) scenarios

Hydropower forms a large share of the current power generation mix of the ACEC countries and additional vast capacity expansions in hydropower capacity are possible. As a renewable technology that can provide both baseload and flexible power output on a large scale, it is of particular value to the reliable operation of an overall system. However, hydro resource availability is also dependent on variability in both climate and weather. It is therefore susceptible to drought, the incidence of which has been rising in recent years in the region. A recent example is the drought along the Zambezi River in 2019, when Victoria Falls almost dried out. Additionally, large hydropower projects are often subject to long approval and construction processes (Taliotis et al., 2014).

Two scenarios have therefore been constructed, based on expert opinion, to present cases where hydro output is reduced, due to (i) limited production per capacity relative to the base case (Dry-year scenario), and (ii) delays in the construction of planned hydro generation projects relative to the base case (Delayed hydro scenario). In the Dry-year scenario, the capacity factors of hydropower plants are reduced to reflect low hydrological flows. In the Delayed hydro scenario, projects are delayed based on their sizes; the start years of projects with capacities above 250 MW are delayed by five years, while those with capacities of more than 1 000 MW are delayed by ten years.

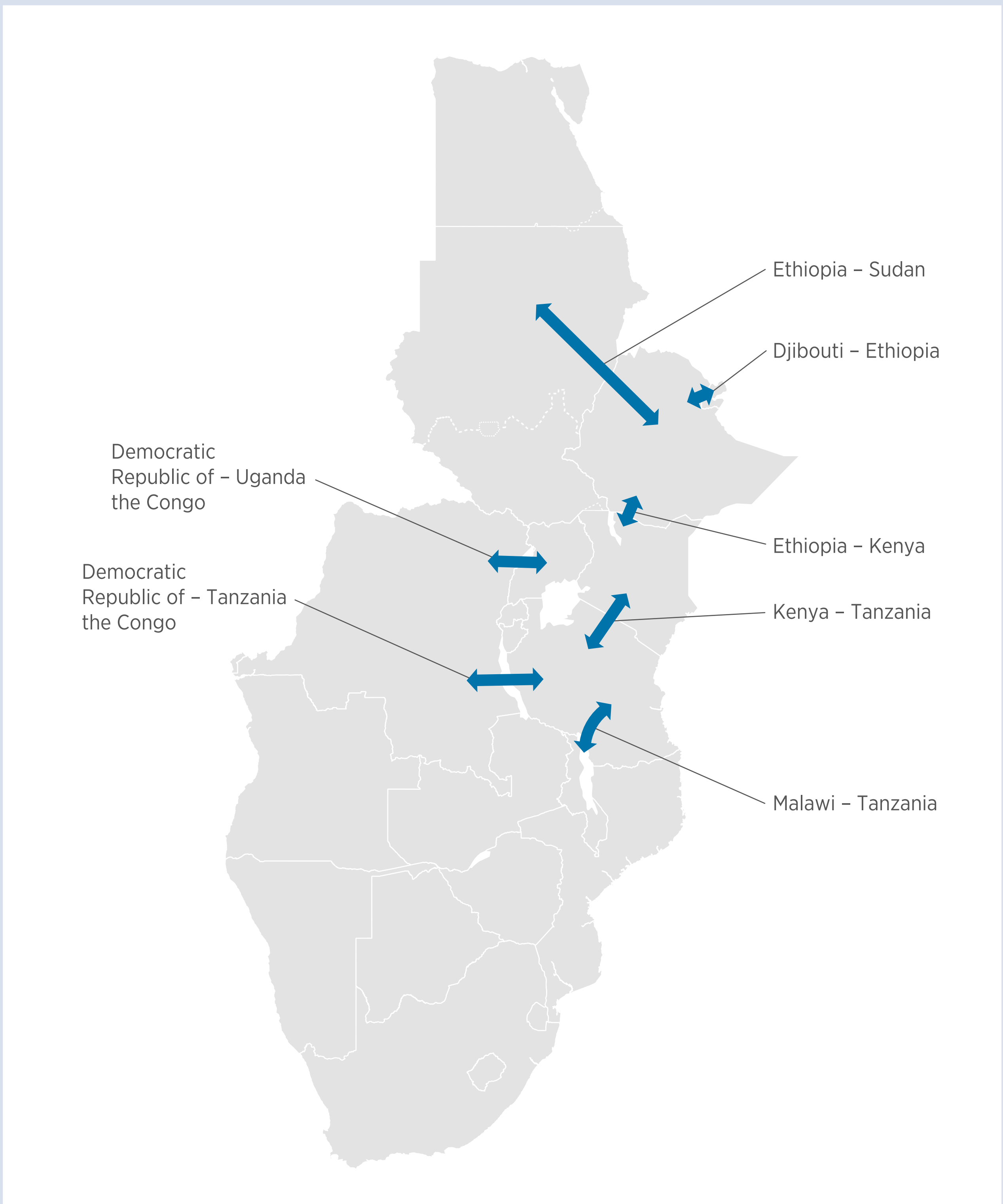
41 The authors recognise the possibility that higher VRE penetration levels are possible. However, these will require policy measures and a study of grid stability, among others, which are not part of the scope of analysis produced by the SPLAT model. At the time of writing, the SPLAT-ACEC model also does not have the granularity required for modelling very high levels of VRE.

4.3.4 Unlimited interconnector capacity expansion scenario (TxNoLim)

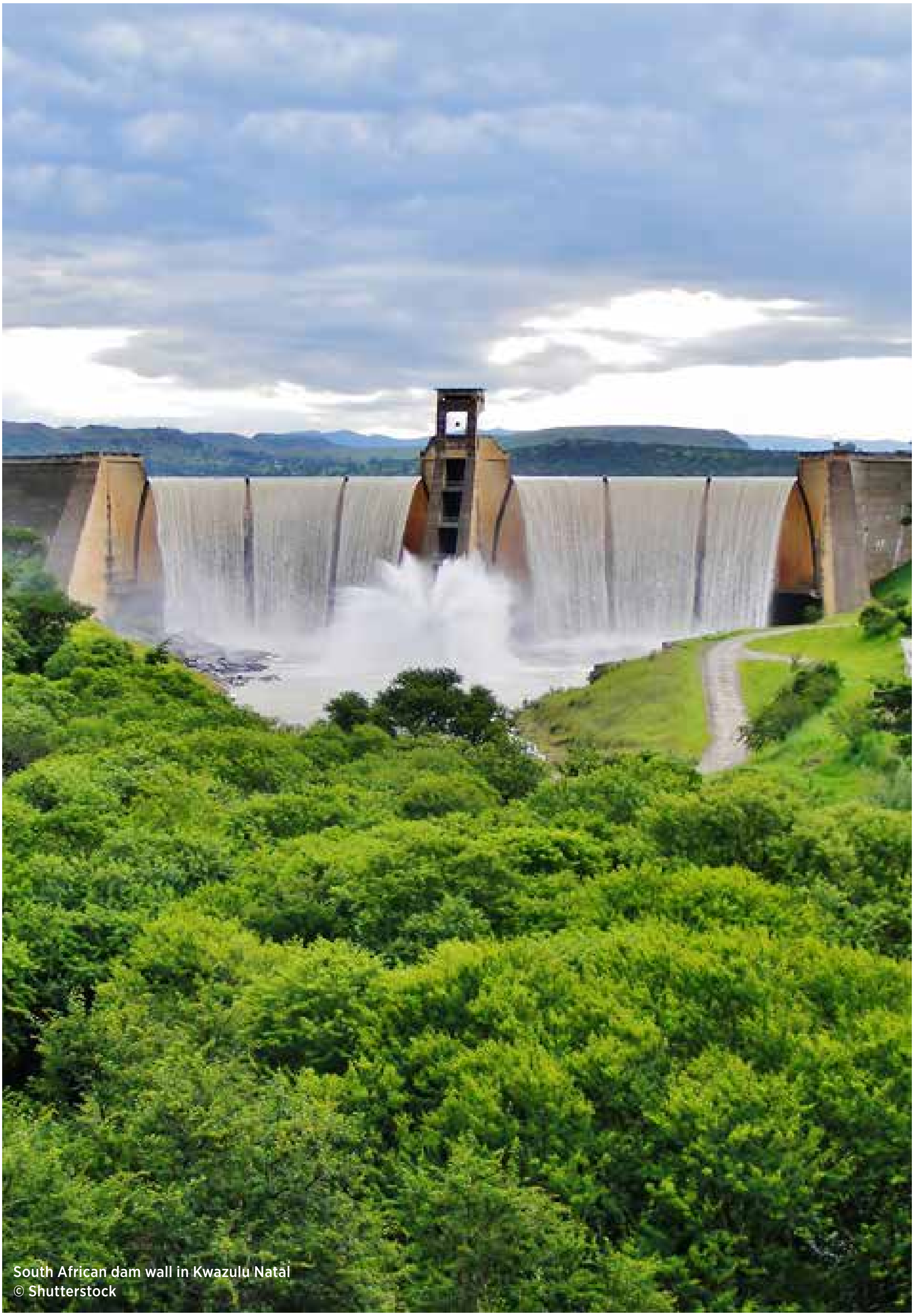
Cross-border transmission network expansions in the region can have an important limiting or enabling impact on levels of power trade and the deployment of renewables in the region. A higher level of trade can help to meet development goals (Pollitt and McKenna, 2014). While transmission expansion in all other scenarios is limited to currently identified projects (some of which are already committed), this scenario seeks to investigate the impact on the power supply mix when capacity build limits on certain interconnectors are fully removed after 2030. Since the planning of transmission projects often takes a long time, it is unlikely that new interconnectors not already in the pipeline (i.e. not committed or candidate) can be built before 2030.

Figure 4-7 shows the interconnectors that are unconstrained after 2030. The rationale for the choice is that a number of these interconnectors (Ethiopia–Sudan, Ethiopia–Kenya, Kenya–Tanzania, Tanzania–Malawi) are along the PIDA North–South Power Transmission corridor (PIDA, 2020). This scenario seeks to identify potential transmission infrastructure projects that can facilitate regional integration in line with the PIDA's aim. For the DRC–Uganda and DRC–Tanzania lines, there are currently neither existing nor planned interconnectors. Interconnectors between country pairs which include large demand sinks (such as Egypt and South Africa) are still constrained to avoid a situation where interconnector corridors are built predominantly to provide for these power sinks. The scenario assesses the regional trade of power, which is less constrained by transmission capacity as compared to the Reference scenario, where interconnectors cannot expand beyond identified plans.

Figure 4-7: Interconnectors that can expand in capacity after 2030 beyond identified options



Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.



South African dam wall in Kwazulu Natal
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INSIGHTS FROM SCENARIO RESULTS

5

This chapter presents and derives in-depth insights from the results of the modelled scenarios defined in Section 4.3. Key findings include the importance of VRE generation in replacing conventional fuels and increasing system diversity, as well as the interaction between transmission and VRE generation. The results in terms of capacity, generation mix, CO_2 emissions, trade flows[42] and system costs are compared across the scenarios. The analysis focuses on the long-term (2040) evolution of the power system while also discussing changes in the medium-term (2030) as key milestones in the transition.

Table 5-1 shows a summary of key results for each scenario. A more comprehensive table with additional results for each scenario can be found in section 7.3 of the Appendix.

Table 5-1: Summary of key results

	Reference	VRELim	VREHigh	HYDry	HYDel	TxNoLim
RE power production share in 2040	62.7%	50.2%	70.7%	62.6%	60.5%	63.2%
VRE power production share in 2040	36%	20%	50%	35.7%	36.9%	36%
CO_2 emissions in 2040 (million tonnes)	357	426	320	371	358	353
Cumulative generation investment[43] required, 2020–2040 (billion USD)	562	480	642	577	578	560
Cumulative investment for interconnectors, 2020–2040 (billion USD)	8	10	8	8	8	14
Overall system cost incl. fuel and O&M costs (billion USD)	2 031	2 053	2 042	2 091	2 050	2 029
Cumulative new wind capacity 2020–2040 (GW)	97.1	49.3	213.6	96.9	101.5	96.5
Cumulative new solar PV capacity, 2020–2040 (GW)	132.4	68.6	127.6	129.7	134.6	133.2
Cumulative new large hydro capacity, 2020–2040 (GW)	40.7	47.5	36.3	36.2	36.9	42.3

42 The volume of trade is a function of electricity price, generation mix, demand pattern and transmission capacity. For the purpose of providing a simplified overview, this report does not differentiate between forms of power trading (e.g. day-ahead vs. intra-day); rather, the focus is on the volume of overall trade taking place. In the model, there is no lead time between building the interconnector and when the interconnector becomes operational.

43 Does not include fuel or O&M costs.

5.1 Significant VRE penetration is integral for realising least-cost pathways

Figures 5-1 and 5-2 show the projected total power generation (in TWh) and capacity mix (in GW) for the region in the Reference Scenario, for the period 2020–2040. Solar PV and wind capacities grow to 232 GW combined (solar PV, 134 GW; wind, 98 GW) and generate up to 36% (579 TWh) of total regional power production by 2040.

In the mid-2020s, the growth in wind capacity leads the increase in solar PV capacity, at approximately 5 GW per year. From the 2030s, solar PV capacity expansion picks up pace, with a range of buildouts from 5 to 19 GW per year. The highest combined yearly buildout of variable renewables – with an addition of 29 GW of solar PV and wind – occurs in 2035. As the capital cost of solar PV and wind decline, while the price of coal rises, solar PV and wind become more cost-competitive relative to coal. Hydropower production also increases slightly.

Under the Reference scenario, approximately 30% of the total capacity (501 GW) in 2040 comprises either currently existing or committed capacities, mainly of hydro or fossil fuel plants. Power generation from coal, which accounts for 42% of today's energy mix, peaks in 2026 (386 TWh), and declines thereafter to pre-2020 levels by 2040. All coal and a significant amount of gas capacities from 2020 onwards are existing or committed.

Figure 5-1: Total electricity generation in the ACEC region (TWh), Reference scenario, 2020–2040

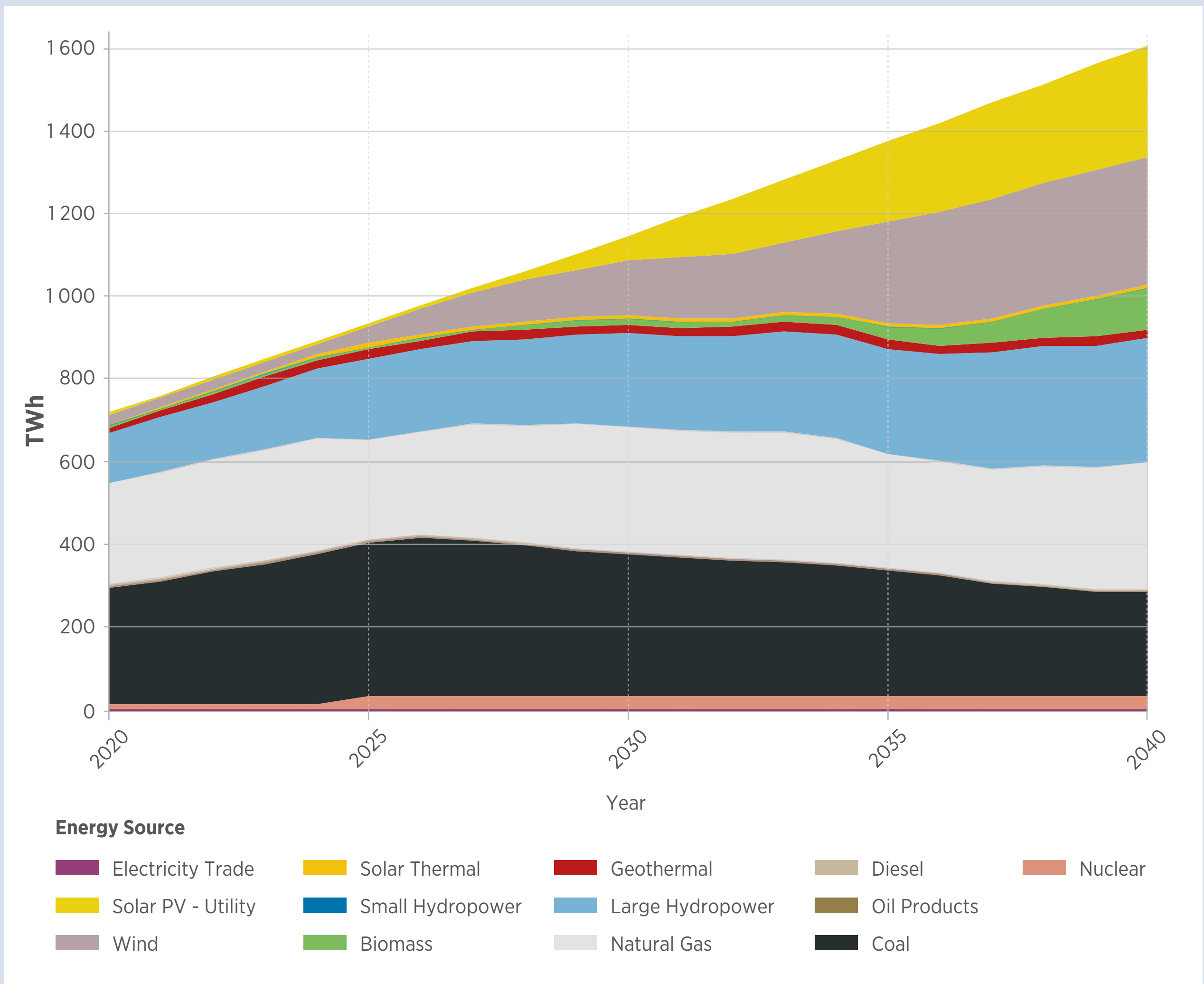


Figure 5-2: Total power generation capacity (in MW) in the region, Reference scenario, 2020–2040

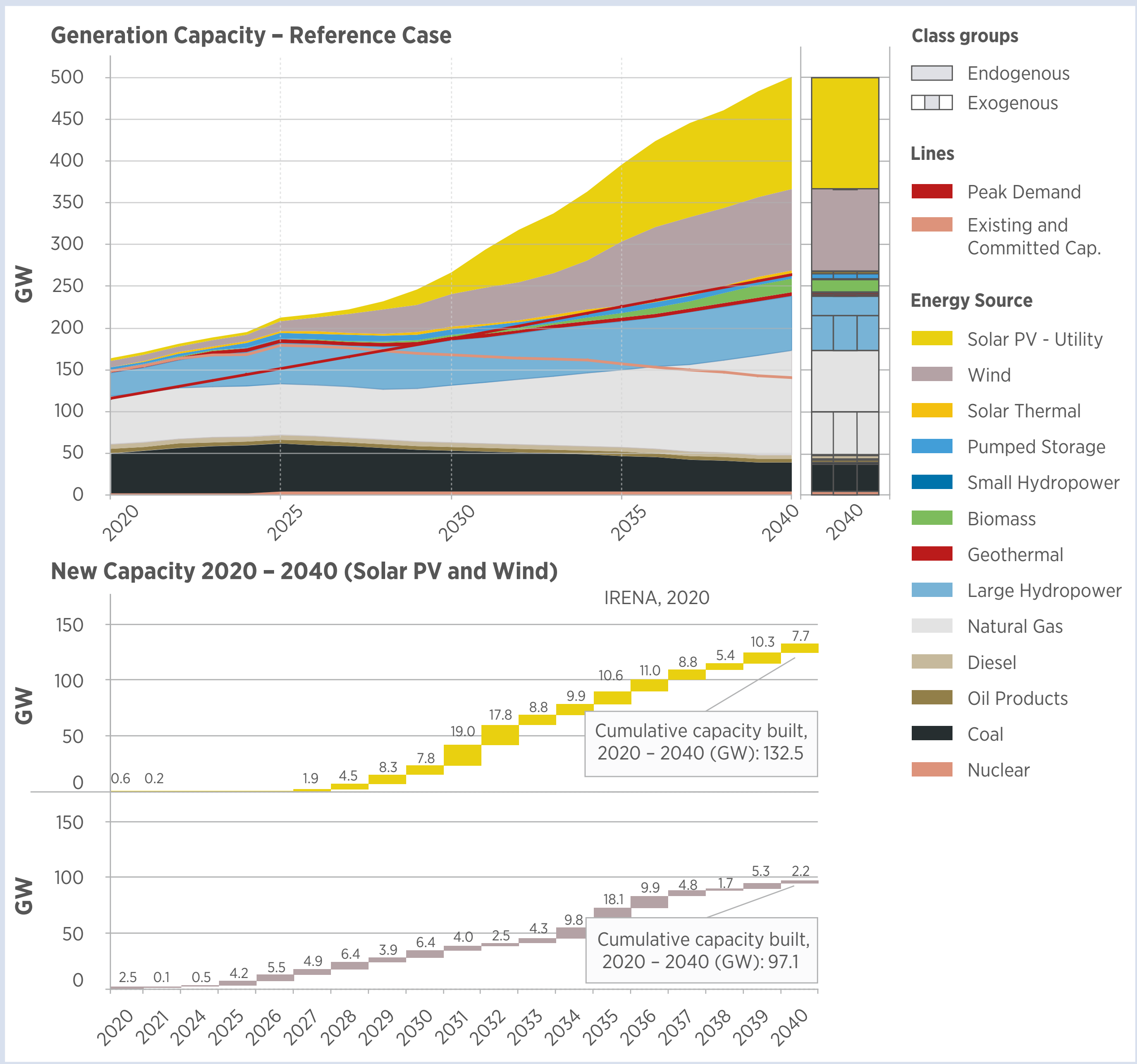
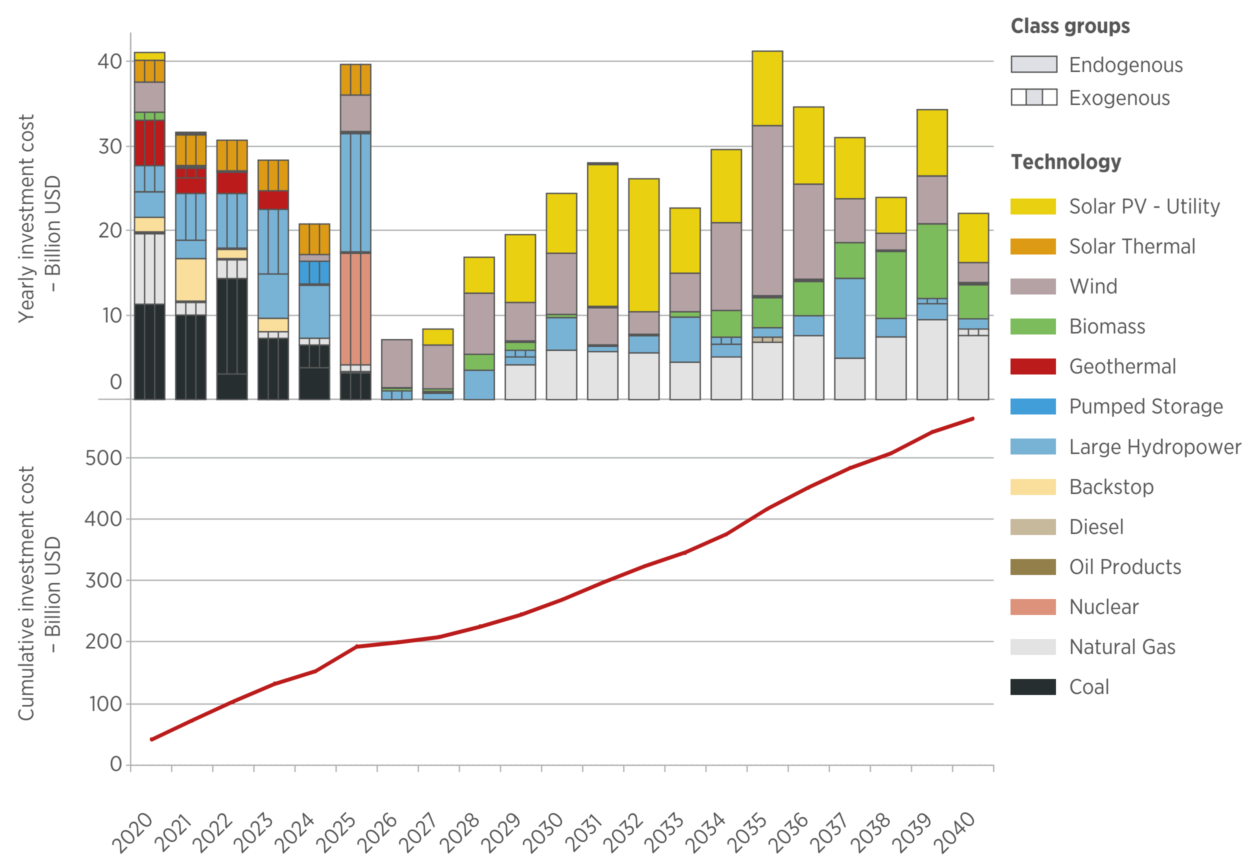


Figure 5-3 shows the yearly investment cost (in 2015 USD) of the Reference scenario from 2020 to 2040, and the cumulative generation investment cost. Cumulatively, USD 562 billion of investment in generation technologies is needed between 2020 and 2040, of which, 148 billion are investments already committed.

Using a discount rate of 10%, the system cost in 2040 – including fuel use and O&M – is USD 134 billion, of which: USD 1 billion is investments in interconnectors; USD 81 billion is generation investments; USD 33 billion is for fuel costs (mostly coal and gas); and the rest, O&M (USD 19 billion). Total system cost from 2020–2040 is USD 2 000 billion. If the pace of renewable deployment is slower (VRELim), an additional USD 22 billion investment in the system is incurred during the period to meet the demand with other technologies. Until 2025, investments are largely in coal, hydro, nuclear and solar thermal technologies, driven by committed plans. From 2026 onwards, following the possibility of developing solar PV and wind zones, investments are largely in solar PV and wind, as well as gas, biomass and hydropower.

Figure 5-3: Yearly and cumulative generation investment cost, Reference scenario, 2020–2040



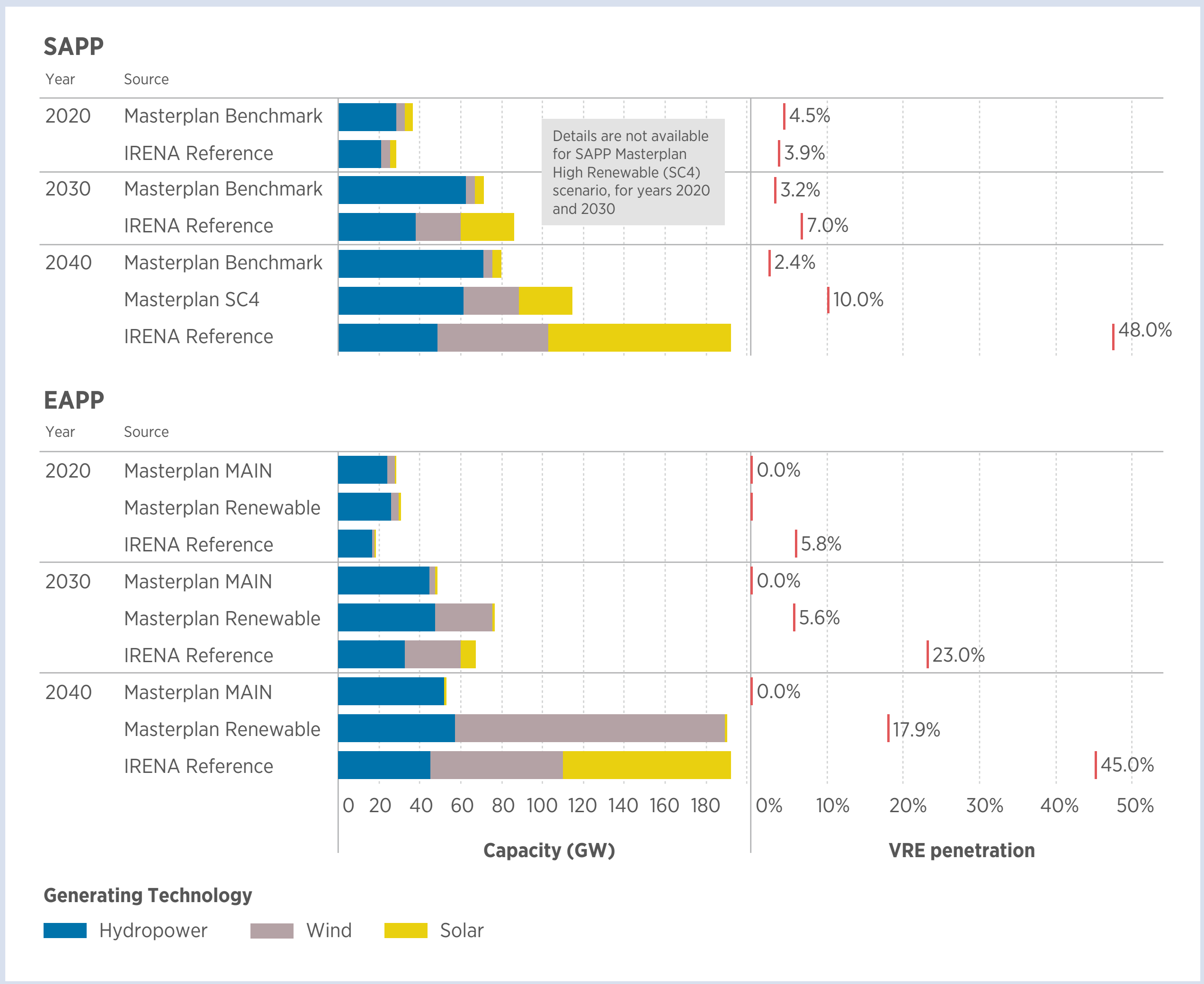
The master plans contain REF-equivalent[44] and high renewable[45] scenarios. Their details are discussed in Chapter 2. Figure 5-4 compares the renewable energy capacities (including hydropower) and VRE deployment between the master plans' scenarios and the REF scenario in this report for the two power pools. From the results of the REF scenario, the least-cost pathway features a high level of VRE deployment, at 36%. This is much higher than the master plans' high renewable scenarios (17.9% for EAPP and 10% for SAPP), indicating that higher ambitions in the two power pools can be achieved based on our cost assumptions and investment options. These differences stem from the inclusion of many more solar PV and wind zone investment options, which are deployed instead of coal and gas options in the REF scenario. The VRE share of each country is shown in Figure 5-10.

Hydropower features prominently in the master plans' scenario results. Even with its consideration, there are still cost benefits to be gained by going beyond the renewable energy targets set by the master plans. According to modelling results, by 2030, the region can meet the renewable energy capacity expectations in the master plans – which comprise mainly hydropower. By 2040, through further deployment of solar PV and wind, renewable energy capacity greatly exceeds the targets of the master plans' scenarios.

44 'MAIN' for the EAPP, and 'benchmark case' for the SAPP.

45 'Renewable' for the EAPP and 'SC4' for the SAPP.

Figure 5-4: Combined RE (solar PV, wind and hydropower) capacity (MW) and VRE penetration in 2020, 2030 and 2040



Sources: from the SAPP and EAPP master plans (EAPP, 2014; SAPP, 2017), and IRENA's modelling results for SAPP and EAPP countries.

Box 5-1: Insights on near-term strategies

Clean energy represents near-term investment opportunities

Figure 5-5 and 5-6 contrast the committed capacities with the candidate projects built from 2015 to 2025,[46] under the Reference scenario. In a majority of the countries, already pledged investments mainly concentrate on coal, hydropower and natural gas technologies. Beyond committed investments, economically-viable candidate options mainly comprise solar PV, wind and hydropower, indicating a demonstratable shift of direction in investment priorities in the near term. ACEC countries need to streamline their policy frameworks and local project facilitation cycles to effectively harness and deploy the requisite financing for renewables.

46 Some countries are excluded in the illustration, given that no new capacities will be needed to cover demand in those countries during this period.

This initial period also serves as an important learning period in which to reduce inefficiencies and enable the timely deployment of larger subsequent waves of new RE capacities, mainly comprising wind and solar.

Figure 5-5: Capacity mix of committed generation projects, 2015–2025

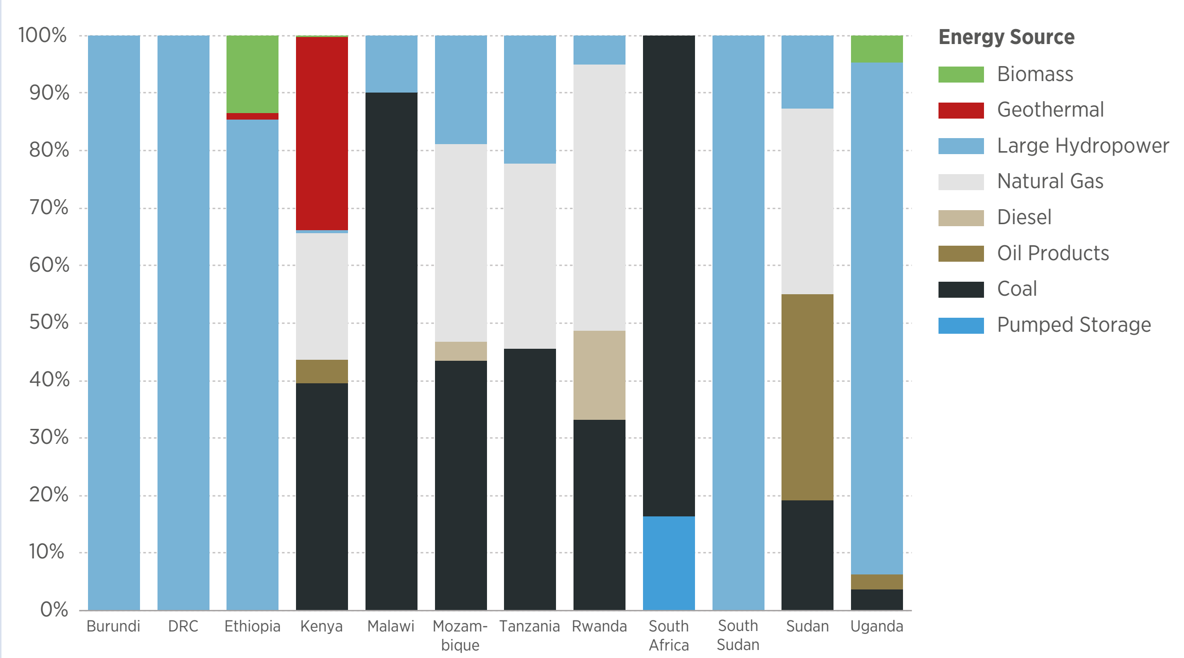
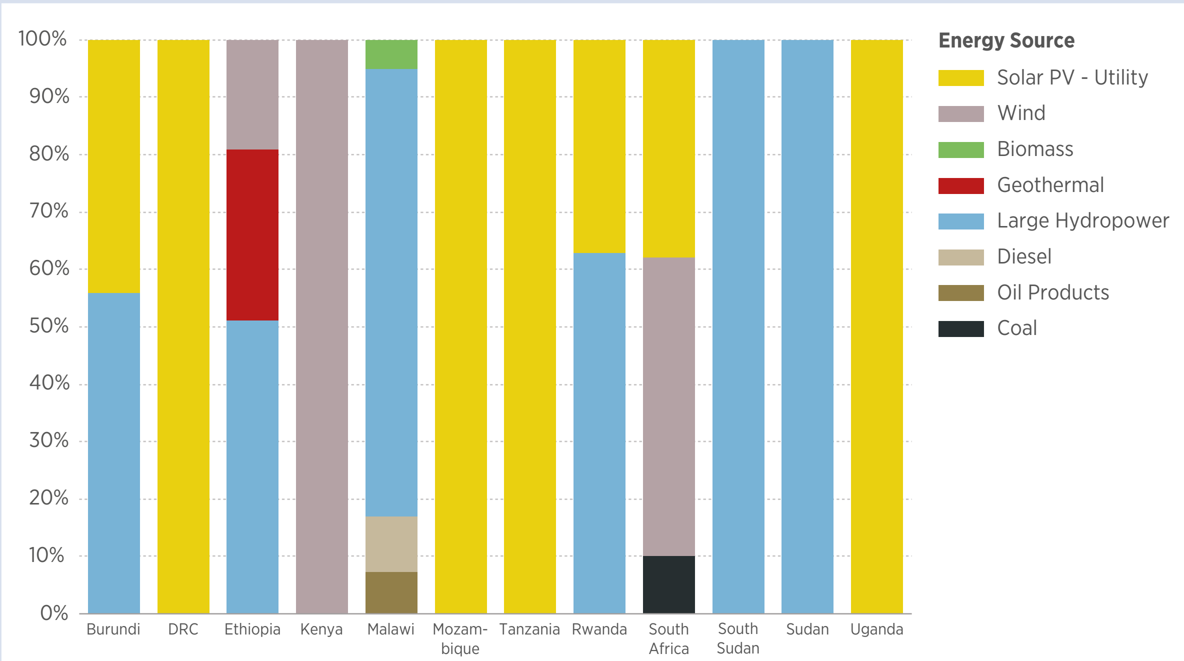


Figure 5-6: Capacity mix of candidate generation projects selected under the Reference scenario, 2015–2025

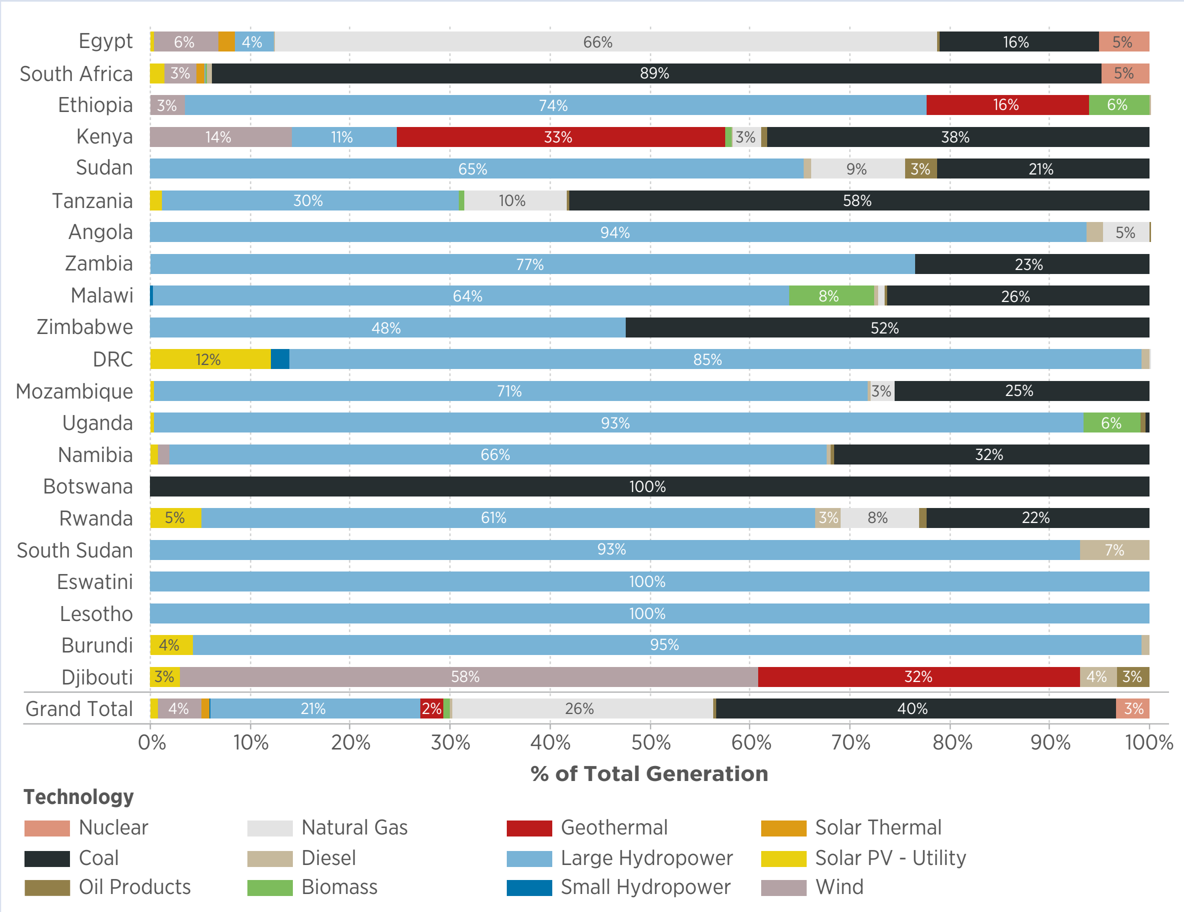


Investments in the near term are required to integrate moderate VRE shares

Figure 5-7 depicts the 2025 generation mix of ACEC countries under the Reference scenario. While investments shift in the direction of VRE, by 2025, most countries have yet to reach high shares of VRE generation, implying limited investment requirements linked with the *integration of VRE* in the near-term. Some countries – namely, Burundi, DRC, Djibouti, Ethiopia and Egypt – see moderate VRE shares in the range of 3–8% occurring alongside sizable hydro or gas generation shares. This is expected, given the favourable flexibility characteristics of hydropower and gas-based generation technologies.

For some other countries, unlocking existing flexibility in domestic power systems is essential, in addition to external flexibility through cross-border trade. This applies to South Africa, which has a high share of coal in 2025. For several other ACEC countries, this is also relevant from 2025 onwards when VRE shares are higher. Unlocking flexibility, in the initial stages, generally involves minor investments to improve the operational and technical flexibility of the system (IRENA, 2018a). Operational flexibility may be enhanced through modernising dispatch planning functions, revising ancillary service requirements and deploying advanced weather forecasting infrastructure.[47] Enhancing technical flexibility may require strengthening the distribution grid at weak spots and upgrading power system control infrastructure. In some countries, such as South Africa, it is worth exploring the financial viability of retrofitting existing, inflexible coal plants to gain higher cycling ability to support the transformation to high VRE shares, as per the Reference scenario.

Figure 5-7: Near term (2025) generation mix, excluding imports



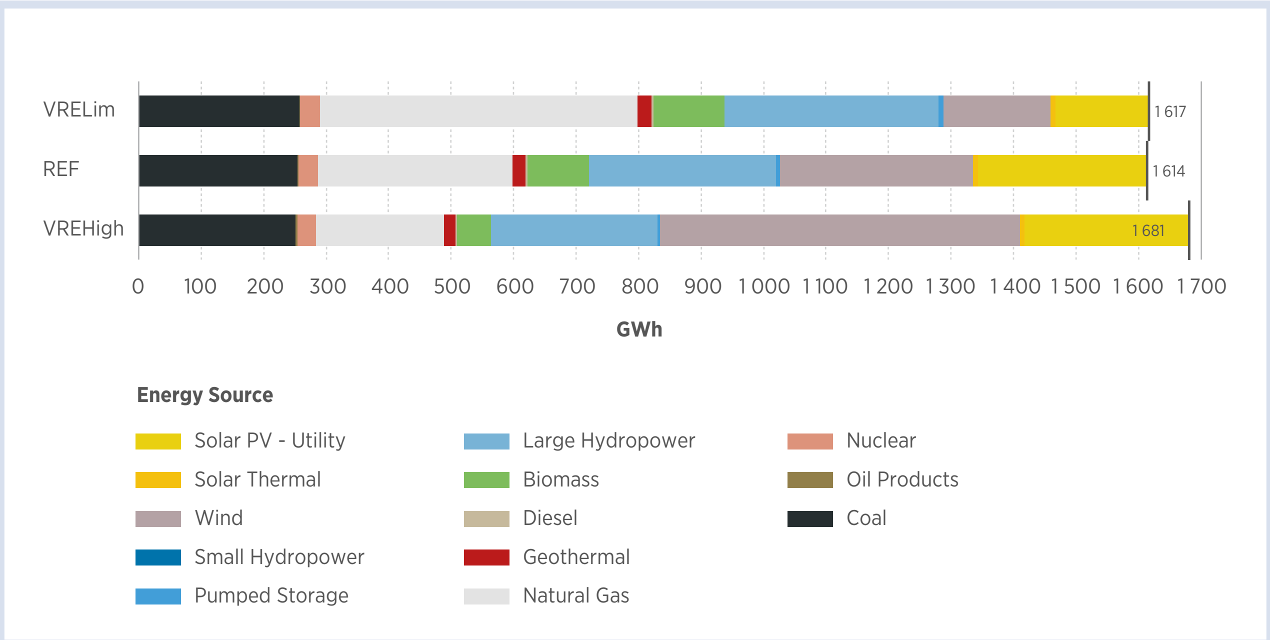
47 Often installed at plant level, such as sky facing cameras, cloud computing, weather modelling algorithms.

5.2 Renewables can replace coal and gas in providing both baseload and peak load power

The VRE scenarios (where VRE penetrations are constrained to 20% and 50% in 2040, respectively in the VRELim and VREHigh scenarios) show which technologies are replaced by VRE in the case of a higher ambition, and which technologies replace VRE in case of limited VRE penetration. In the higher ambition case (VREHigh), natural gas is reduced and compensated for by an increase in wind. At the same time, gas replaces solar PV and wind when VRE penetration is limited (VRELim). Coal generation remains largely the same across all three scenarios, as coal's comparatively lower prices than gas prevent it from being edged out of the supply stack when VRE penetration varies.

Figure 5-8 shows the differences in power generation between the VRELim and VREHigh scenarios. With an ambitious 50% VRE penetration target in 2040, roughly 107 TWh of natural gas (of which 100 TWh is from Egypt) are replaced by wind, whose production is higher by 267 TWh compared to the Reference scenario. The dominant rise of wind over solar PV is due to it being a more favourable substitute for gas that can operate throughout the entire day. Solar PV can only be produced in the day, so its role in displacing baseload gas during night hours is limited. A total surplus generation of 65 TWh is to be curtailed. Storage technologies or transmission upgrades may be considered to reduce this amount.

Figure 5-8: Comparison of the Reference scenario, VRELim and VREHigh, 2040



If the pace of VRE penetration is limited, a different picture emerges, as a large part of VRE generation (199 TWh) from the Reference case is instead produced from natural gas. VRE generation is 257 GWh lower by 2040, and VRE capacity is 112 GW lower. This translates into lower investment costs from a lower build-out of solar PV and wind capacities, which, however, are offset by higher O&M and fuel costs from using more natural gas.

This report does not consider the mothballing or early retirement of generation options. The future retirement schedule for coal capacity is exogenous and identical across all the three scenarios.

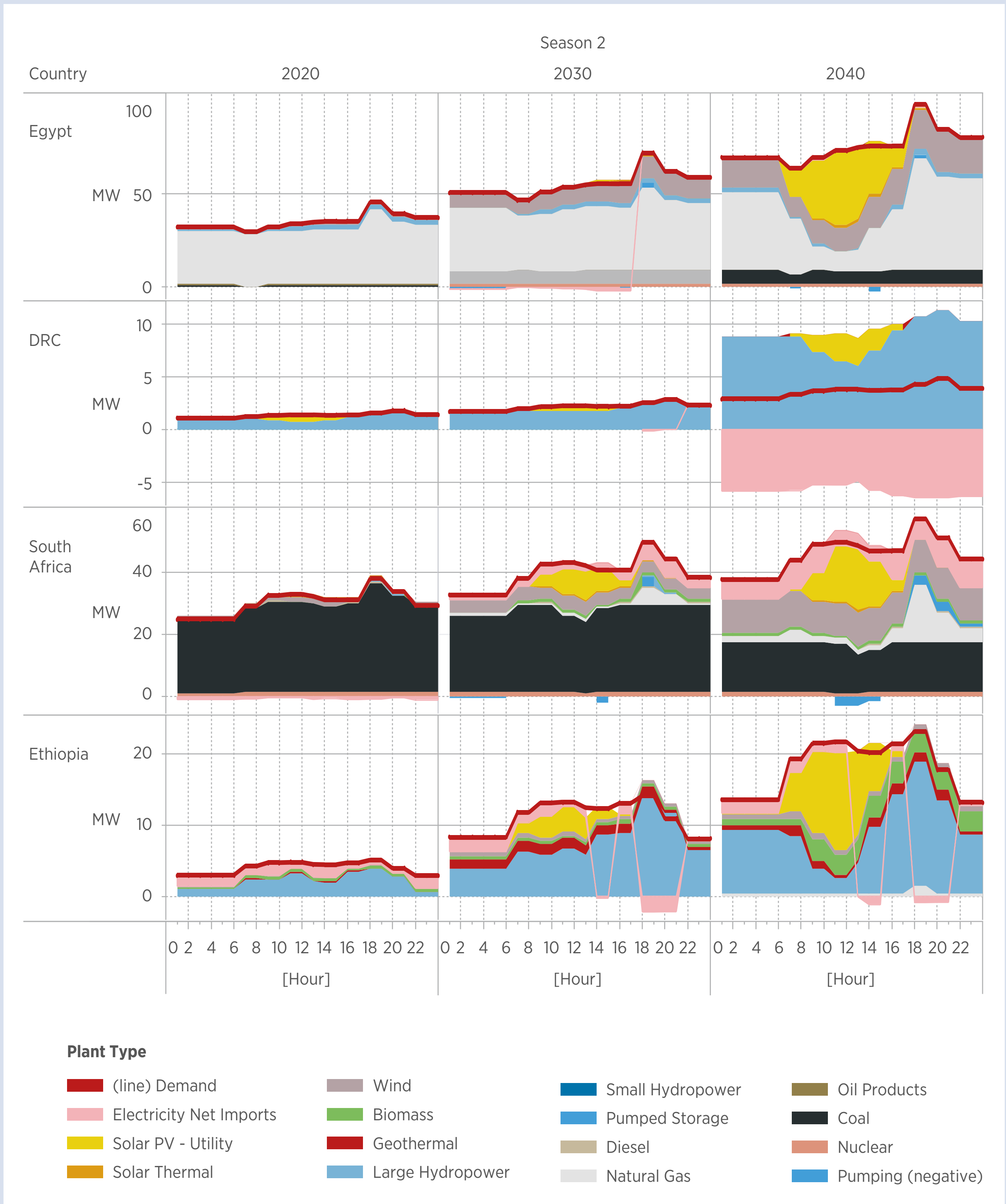
Hourly generation profiles on each seasonal day considered show how the generation mix evolves diurnally with demand and reveal the patterns of production of different generation technologies. These profiles can provide insights into trends at higher temporal granularity, which aggregated yearly figures cannot.

Figure 5-9 shows the simulated hourly generation profiles of four exemplary countries in the years 2020, 2030 and 2040 under the Reference scenario during season 2 (May–August). Across all four countries, the increase in VRE generation from solar PV and wind substitutes conventional generation throughout the day. Although the output of individual wind farms can vary throughout the day, by distributing the wind farms geographically, the collective generation shows less variability. Furthermore, demand growth in these countries is almost entirely met by generation from renewable sources.

In Egypt, where there are high levels of wind and solar PV potential, demand in the day can largely be met by VRE generation, displacing current generation from natural gas. Similarly, in South Africa, baseload generation from coal is mostly substituted by production from wind, while solar PV contributes to meeting demand during daylight hours.[48]

48 The effects of the ramping limitations of coal plants are approximated by the use of an availability factor.

Figure 5-9: Hourly generation for season 2 (May–August) in Egypt, DRC, South Africa and Botswana, in the years 2020, 2030 and 2040

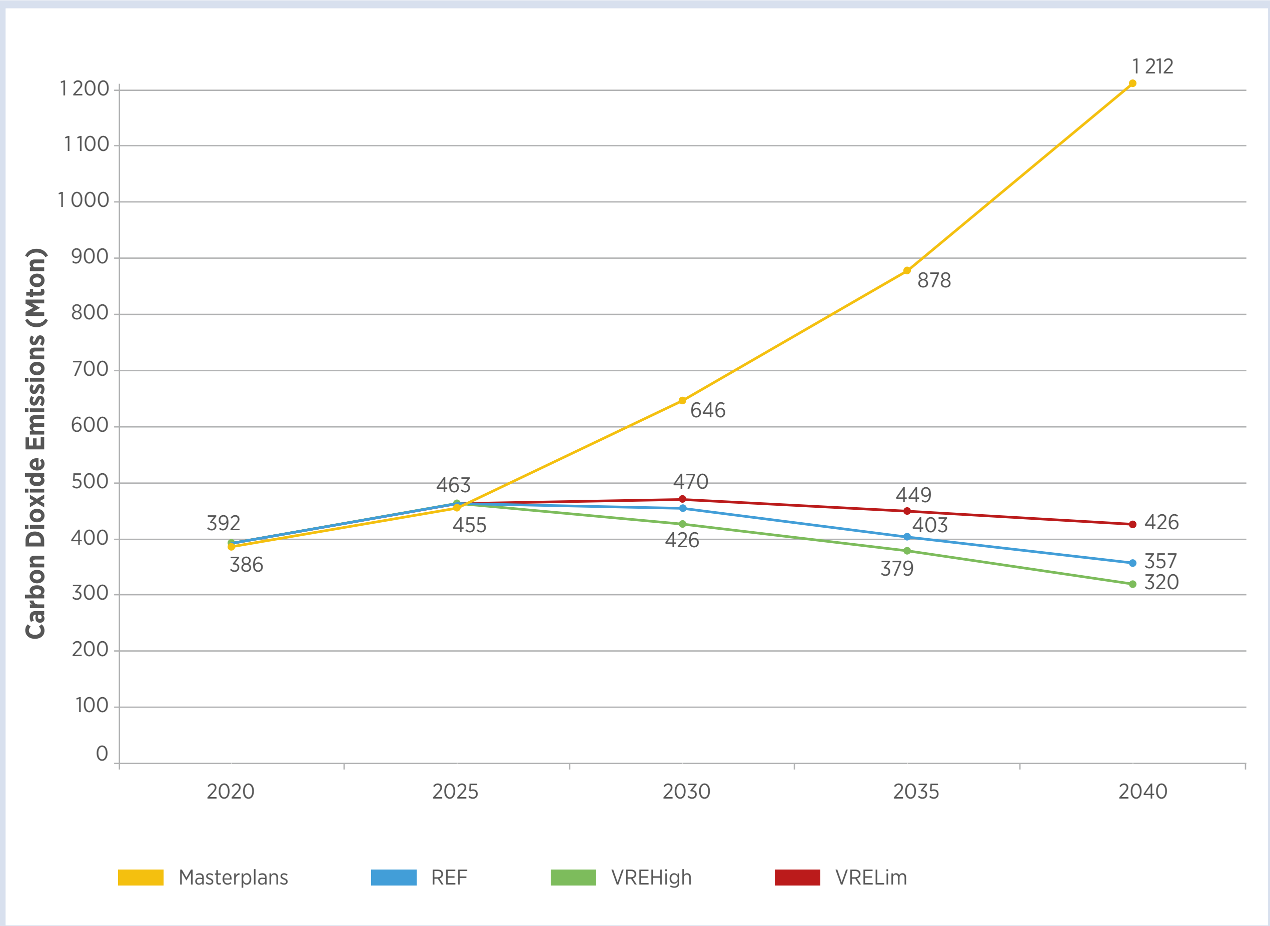


Disclaimer: VRE plays a significant role in generation in 2040; hours in SAST (UTC+2:00).

5.3 Carbon emissions are reduced when VRE displaces coal and gas

Under the coal-dominated futures of the EAPP and SAPP master plans, CO_2 emissions rise to 1212 megatonnes per year in 2040 based on the master plans' base case scenarios. With continued reliance and expansion of coal generation capacity in the master plans, CO_2 emissions are more than triple the emissions in IRENA's Reference scenario (357 megatonnes). Figure 5-10 depicts the yearly emissions (in megatonnes) as projected by the master plans and from modelled results. Even with the high renewable scenarios of the master plans, the levels of CO_2 production are reduced but not drastically so, as the generation shares of renewables in these scenarios are only modestly higher (20% vs. 44% in the EAPP,[49] 39% vs. 27% in the SAPP in 2040), replacing 12–24% of generation from fossil fuels. Considering the large share of power generation by South Africa, it also has the highest potential emission reductions when compared against the master plan.

Figure 5-10: Total yearly CO_2 emissions (in megatonnes) from the base cases[50] of the master plans (EAPP, 2014; SAPP, 2017) and IRENA's Reference (REF), VREHigh and VRELim scenarios



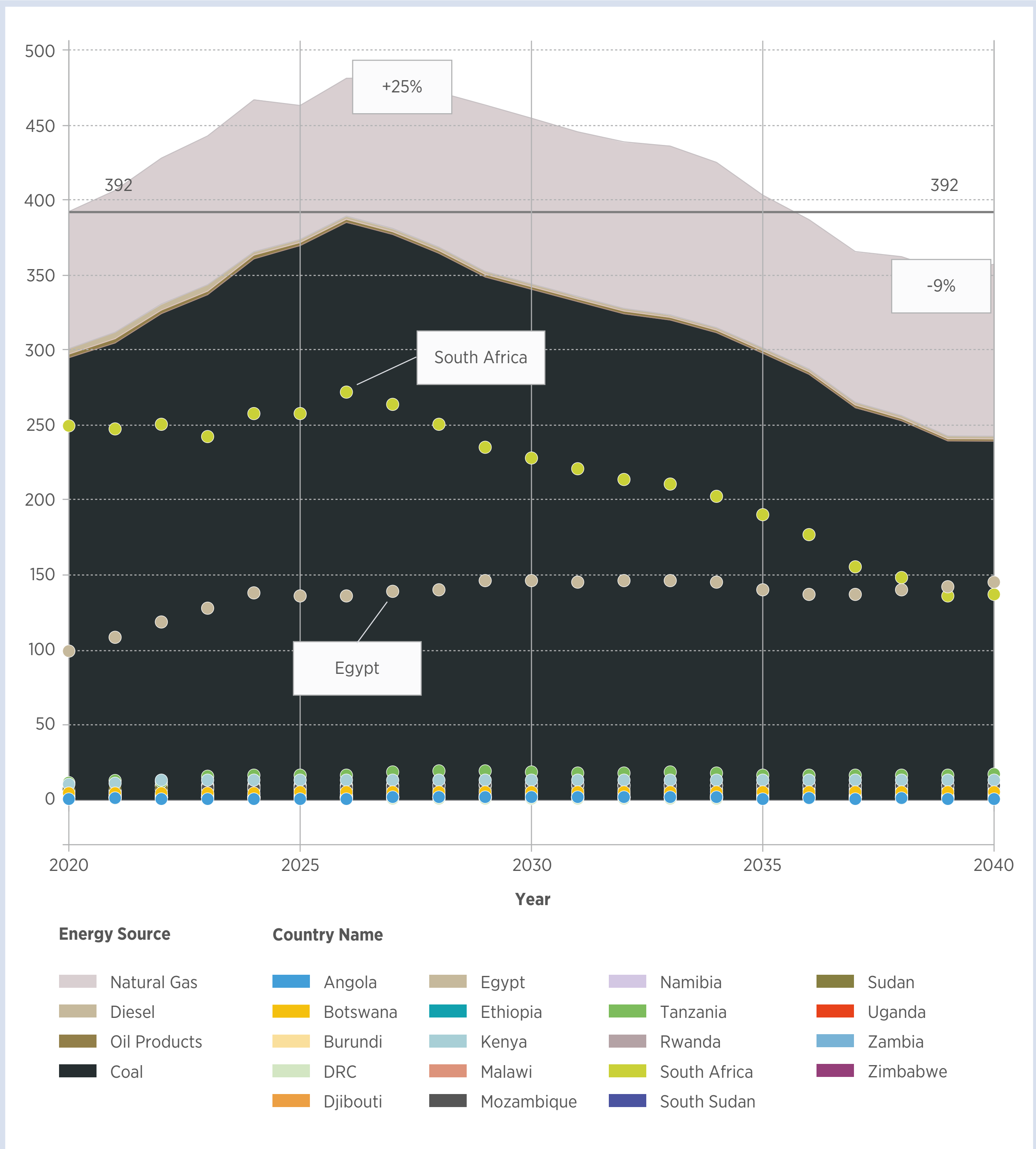
Disclaimer: values here only relate to emissions from electricity production.

49 Excluding Libya.

50 The SAPP Master plan presents only shares of production rather than total generation number for the high renewable scenario. The EAPP Master plan also does not report the carbon dioxide productions for the renewable scenarios.

In the Reference scenario, CO_2 emissions peak in 2026 (489 megatonnes, 25% more than 2020), followed by a gradual decline to pre-2020 levels (9% less than 2020). The main reason for the CO_2 emissions reductions is the reduced reliance on coal in South Africa, as there is more deployment of solar PV and wind. Figure 5-11 shows CO_2 emissions (in megatonnes) from electricity production by technology for the Reference scenario, alongside the CO_2 output from selected countries with significant emissions.

Figure 5-11: Total CO_2 emissions (in megatonnes) from electricity production by technology, REF scenario, 2020–2040



In addition to the EAPP and SAPP master plans, which partially govern the ACEC regional narrative on how its power generation sector evolves in the medium to long term, country specific NDC commitments are increasingly entering the limelight. Emission reduction is becoming a key priority among ACEC countries. However, currently the ambitions stated in country NDC/INDCs lack comprehensive commitments for the power generation sector. Box 5-2 provides some context to global NDC ambitions and how selected ACEC countries stand in terms of their official NDC commitments in the power generation sector vis-à-vis the IRENA Reference scenario.

Box 5-2: Informing Nationally Determined Contributions with long-term energy scenarios

Countries are encouraged to cut energy-related carbon dioxide (CO_2) emissions through commitments in their Nationally Determined Contributions (NDCs) by scaling up renewables. As part of the “ratchet mechanism” of the Paris Agreement, the NDCs are to be revised in 2020 and every five years thereafter. This includes expanding the ambitions for renewable energy deployment.

The first round of NDCs pledged under the Paris Agreement fall short of meeting climate goals. The new NDC round starting in 2020 represents an opportunity to strengthen targets for renewable energy in electricity generation. According to IRENA’s NDC brief released at the global climate meeting (COP25), 140 NDCs mention renewables in the power sector, but only 105 of the 140 include quantified targets for renewable electricity (IRENA, 2019).

ACEC scenarios can inform the renewal of variable renewable energy (VRE) capacity targets in the EAPP and SAPP. Table 5-2 shows a comparison between the new RE deployment targets stated in the NDCs and the additions possible in IRENA’s VREHigh scenario, in selected countries. A regional target can encourage countries to make better use of their VRE endowments.

Table 5-2: New capacity renewable energy targets in NDCs for selected countries compared to the ACEC VREhigh scenario

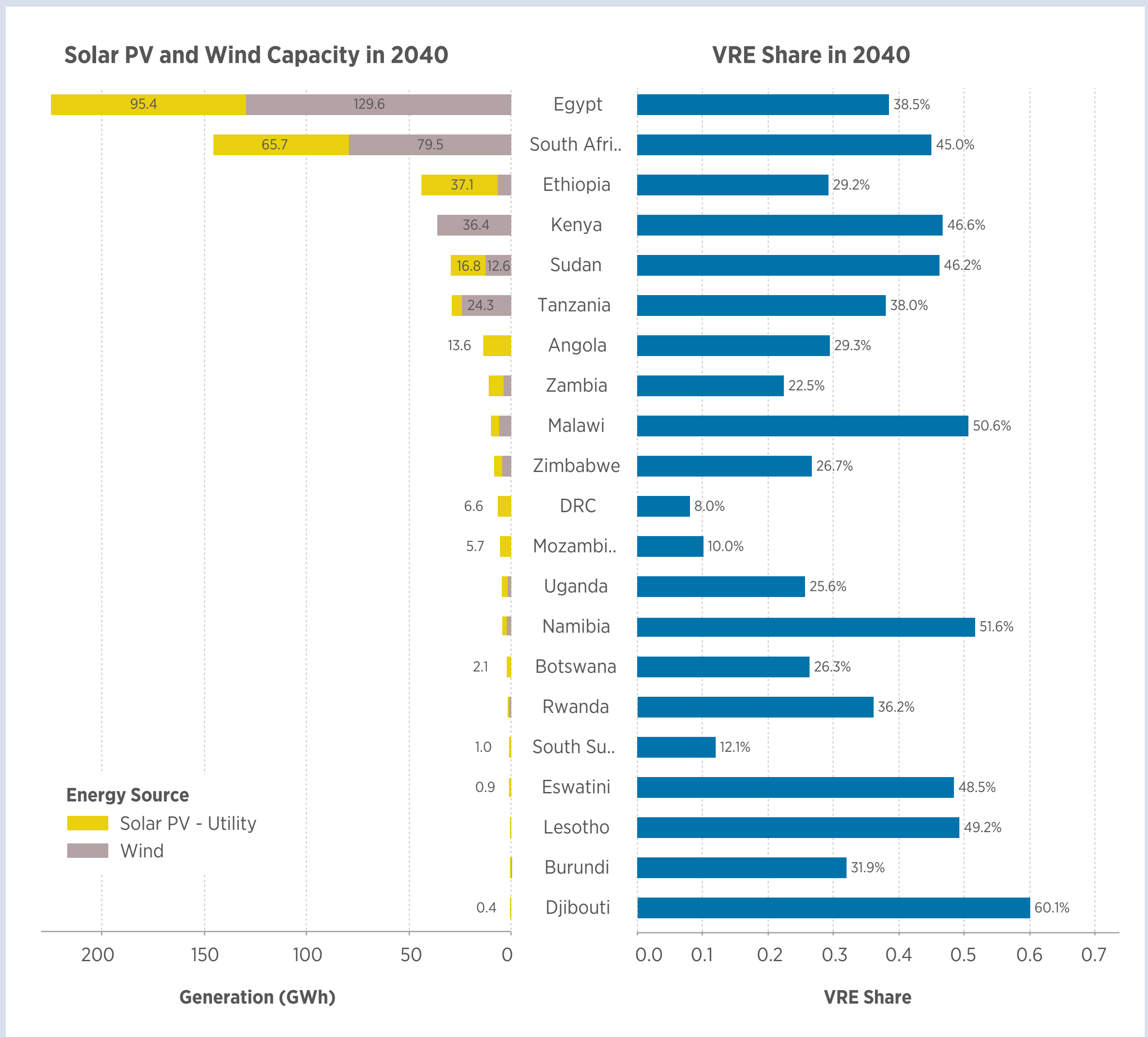
Country	New RE installed capacity indicated in NDC/INDC by 2030 (MW)	New RE installed capacity under the ACEC VREhigh scenario by 2030 (MW)
Botswana	No new RE targets mentioned	790
Ethiopia[1]	6 000	26 000
Mozambique	No new RE targets mentioned	4 000
Uganda[1]	2 460	2 800
Zambia[2]	60	4 200
Zimbabwe[2]	1 511	3 400

Disclaimer: [1]taken from (IRENA, 2018b);
[2]assessed inhouse from country NDC/INDC review.

5.4 Cost-effective VRE projects are geographically dispersed

Due to the geographically widespread VRE resources, smaller countries such as Djibouti, Eswatini, Lesotho, Malawi and Namibia can also cost-effectively achieve 40% or higher VRE shares. Figure 5-12 shows the solar PV and wind generation in the Reference scenario in 2040, alongside the percentage of VRE generation for each country. While Egypt and South Africa account for a large share of additional VRE capacity buildout in the region due to their high power demand, the relative VRE share in the two countries is similar to that of the other ACEC countries. In countries that have lower hydro VRE shares, such as the DRC, Mozambique and South Sudan, there are large shares of hydropower (240%, 98% and 91%, respectively) for net exporting to neighbours, thereby dampening the percentage share of VREs (Figure 5-19). Checking the VRE shares against the SAPP and the EAPP master plans' base cases show that the two master plans estimate much lower VRE potentials for all countries in the region (27% and 42% respectively, as determined by the master plans).

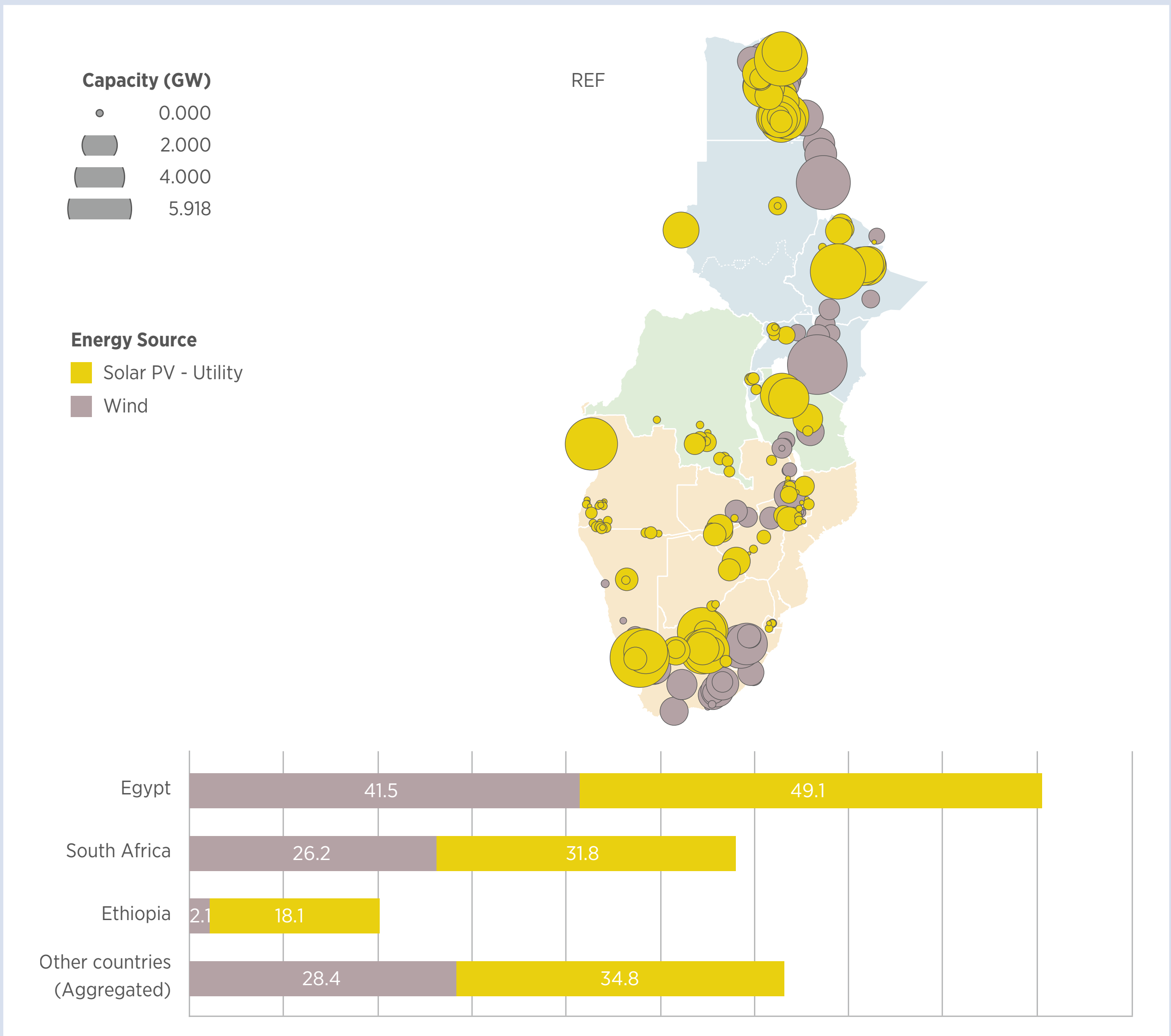
Figure 5-12: VRE generation and share of generation by country in the Reference scenario, 2020-2040



Since the region has excellent resources that are geographically diverse, solar PV and wind deployment are observed throughout the corridor, most prominently in Egypt and South Africa where large numbers of project zones are considered. The visualisation of the location and capacity of solar PV and wind plants in 2040 for the REF scenario is presented in Figure 5-13. Each bubble represents one zone for VRE deployment (see Section 3.2), while the size indicates the respective zone's estimated capacity in 2040. Each country has its fair share of opportunities. A higher share of VRE generation (VREHigh) prompts additional buildout of solar PV capacity in South Africa and wind capacity in Egypt, Ethiopia, Malawi, Mozambique, Tanzania, Zimbabwe and Zambia.

Although the generic plants modelled have lower capacity factors than project zones, some generic solar PV and wind plants also turn up in the results if they can better meet demand at certain periods than the identified project zones. (For a definition of the plant categories, refer to Section 4.2.3.)

Figure 5-13: Generation capacities of solar PV and wind in Reference scenario, 2040



Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

Box 5-3: Investment options identified through a modelling study vis-à-vis readiness of investment options

The technology options evaluated by the modelling analysis reflect opportunities under broad technical and political constraints. Conclusions from the modelling analysis would serve as beneficial references for governments in setting renewable deployment targets, promoting particular technologies for reducing carbon dioxide emissions and diversifying their generation mixes. Assessing the technology options as a part of an overall power system allows an assessment of the monetary investment needs for realising different configurations of the power system.

While these technology options assessed in the analysis represent investment options, model-based analysis typically does not aim to represent a full range of barriers to investment, e.g. those due to institutional and geopolitical constraints. Some of them may be represented in scenarios, as in our case with the delayed hydropower scenario. In-depth discussions on investment risks, the creditworthiness of countries and utilities, and payment behaviour are beyond the scope of this report. Readers may refer to other studies, such as on risk mitigation strategies (IRENA, 2016) or sovereign guarantees (IRENA, 2020c).

In addition to the areas above, understanding the challenges and opportunities related to trading requires study of the management of off-taker risks and various types of trading structures. For a guide on interconnection project design and preparation, readers may supplement this report's high-level representations of investment timelines with the World Bank's PPPIAF toolkit on building regional power pools (World Bank Group, 2018).

IRENA's instruments for project implementation are outlined in Box 6-1.

5.5 RE investment is a robust strategy against hydro-related risks

Those power systems that have a moderate amount of hydropower can be robust if planned accordingly, reaping benefits from both the dispatchable and storage capabilities of hydro dams. However, there can be risks to the security of supply for systems that rely heavily on hydropower, if the availability of water is reduced during extended periods of drought, or when hydropower projects are delayed for financial and regulatory reasons (as with other types of large generation projects). Systems that comprise a diverse mix of primary energy are better able to withstand shocks, constraints and crises affecting supply. This report finds that power systems in the region can respond to hydro-related risks by complementing hydropower with other sources of renewables.

The diversity of the supply mix evolves with hydro capacity buildout and availability. Figure 5-14 compares the eventual hydropower share across all countries for all hydro scenarios. In most countries, the delay of hydro projects (HyDel) does not affect the ultimate hydro production in the country, as these projects go on to produce the same as the REF case after they build later on in the model. However, in the interim, other renewables (geothermal energy, biomass, solar and wind) can serve as alternative generation options to meet the supply gap.

A hydropower plant often operates beyond 50 years and had been designed based on historical hydrological observations, exposing them to climate changes spanning several decades. While hydro dams can be used to supply water during dry seasons within a year, climate change can potentially impact the availability factor of hydropower by causing droughts and reducing river flows over multiple years (HyDry). For example, Zambia was affected by low hydrology from 2014 to 2016, resulting in a 50% reduction in hydroelectric generation, and again in 2018–2019 (Trace, 2019). In such circumstances, other forms of renewables can step in as robust investments to fill the generation gap. When the hydro availability factor is reduced (HyDry; 77 TWh in 2040), significant reductions in the share of hydropower production are observed for Burundi, South Sudan and Uganda. These countries are most sensitive to changes in hydro resources and can use alternative renewable energy sources to diversify the system when they are limited. In Burundi, South Sudan and Uganda, mainly biomass contributes to diversifying the system.

Figure 5-14: Share of hydropower production for all countries, 2040

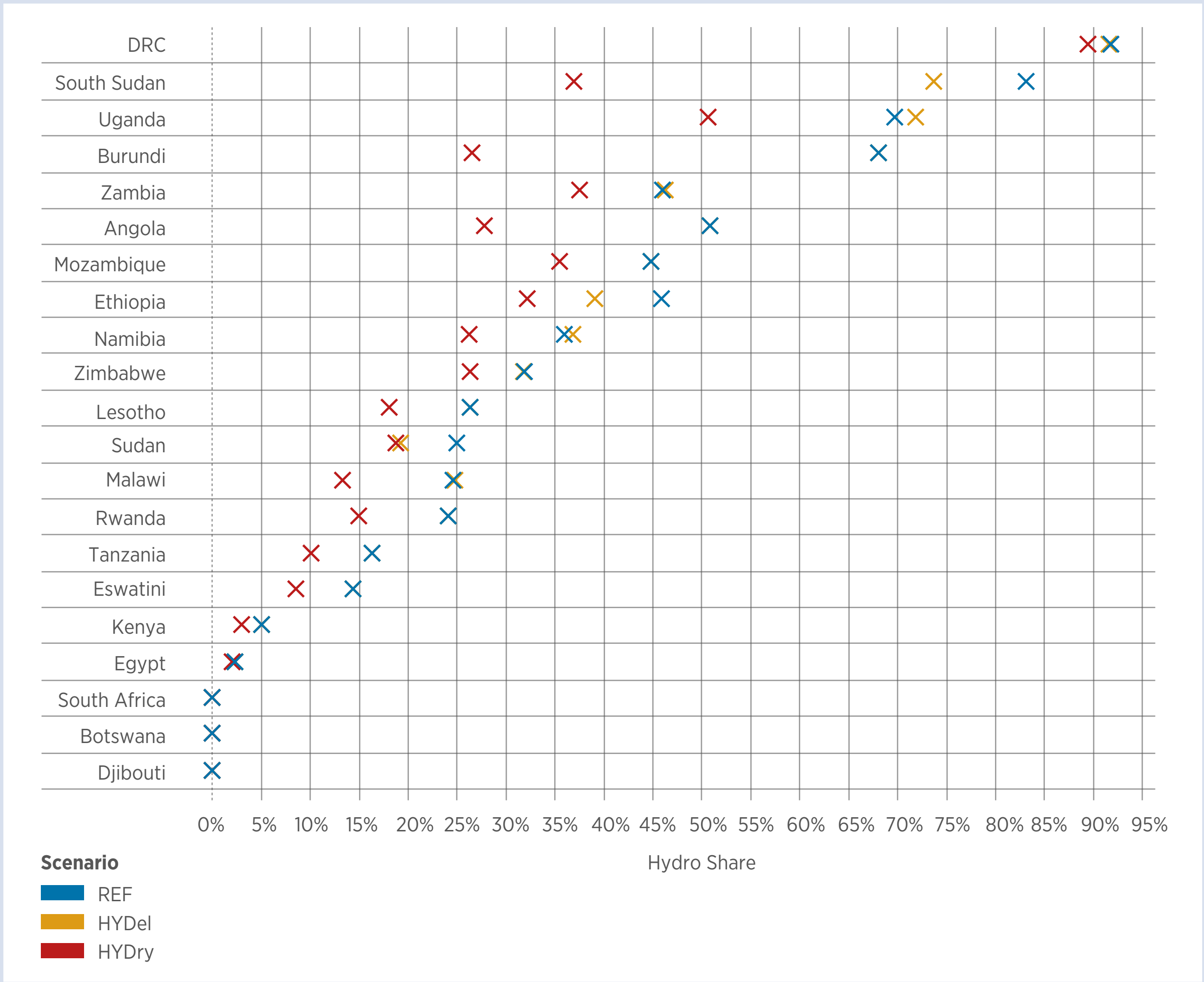


Figure 5-15 shows the generation differences of the HYDel and HYDry scenarios relative to the Reference scenario from 2020 to 2040. In both cases, hydro production is lower compared to the Reference case for all years, while production from other sources serves as a substitute. These sources are solar, wind, biomass and geothermal in the HyDel scenario, with gas and coal in the early years. In the HyDel scenario, these sources include solar, wind, biomass, geothermal and gas.

Figure 5-15: Generation (MWh) differences of the HYDel and HYDry scenarios relative to the Reference scenario, ACEC region

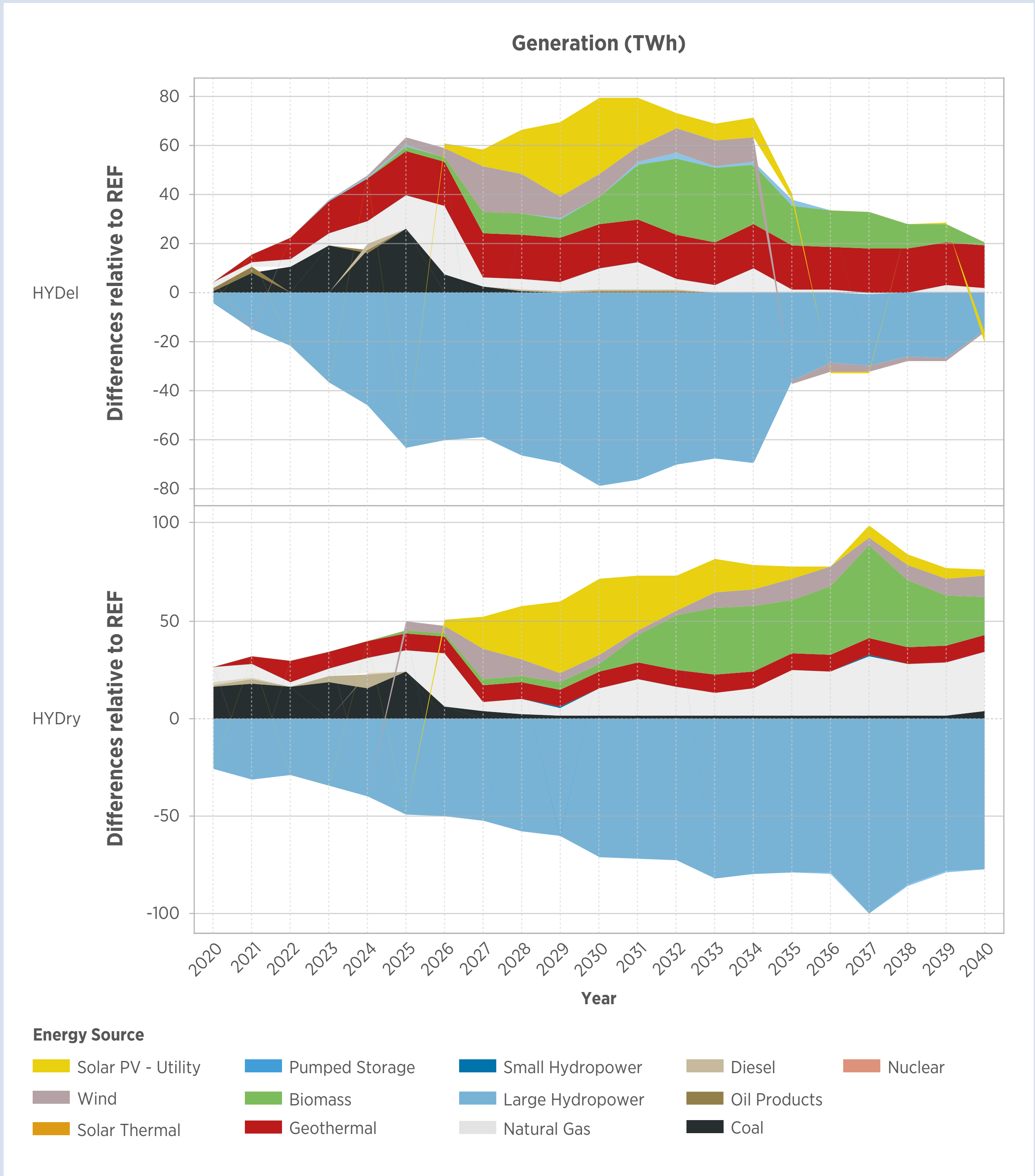
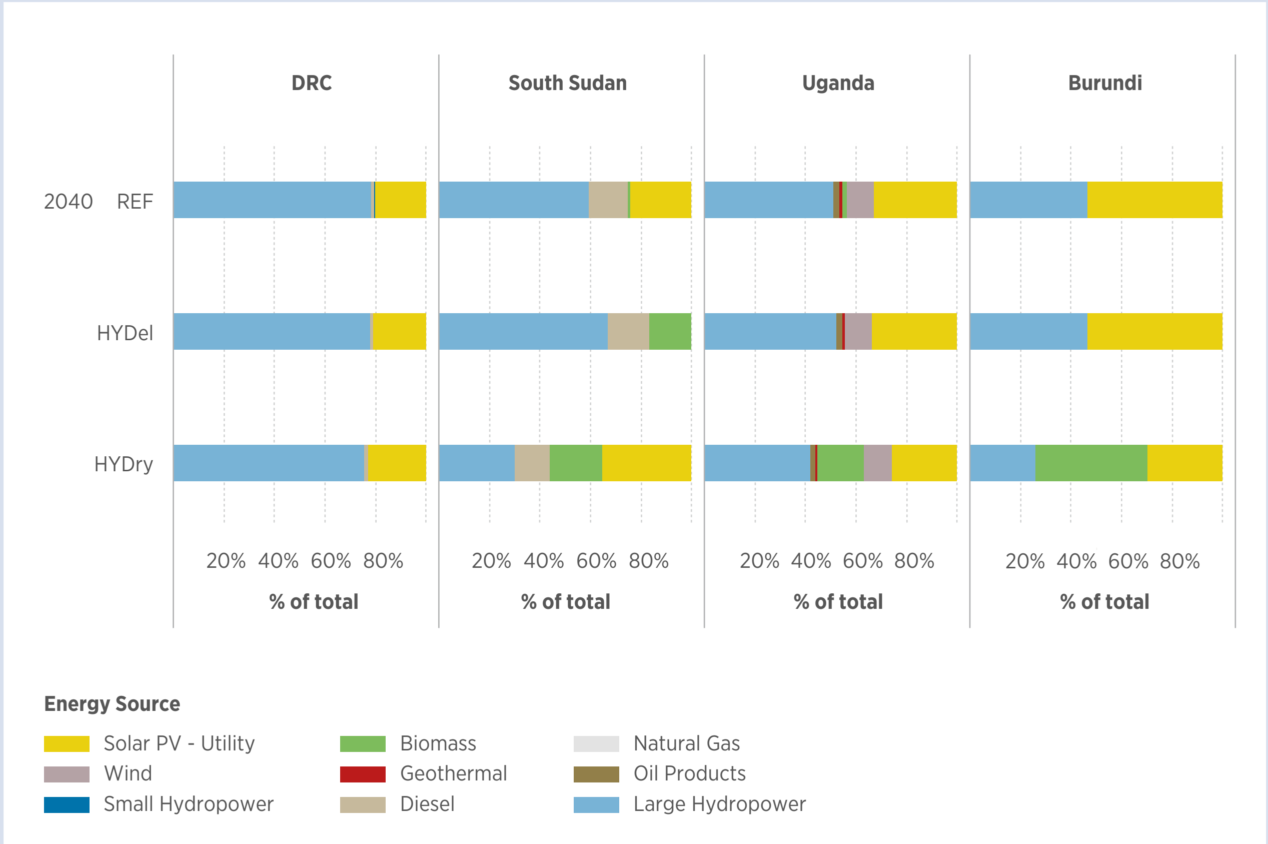


Figure 5-16 shows the generation mix of the four countries (DRC, Uganda, South Sudan and Burundi) with the highest hydro shares in the region.

Figure 5-16: Generation mix of the four countries with the highest hydro shares, 2040

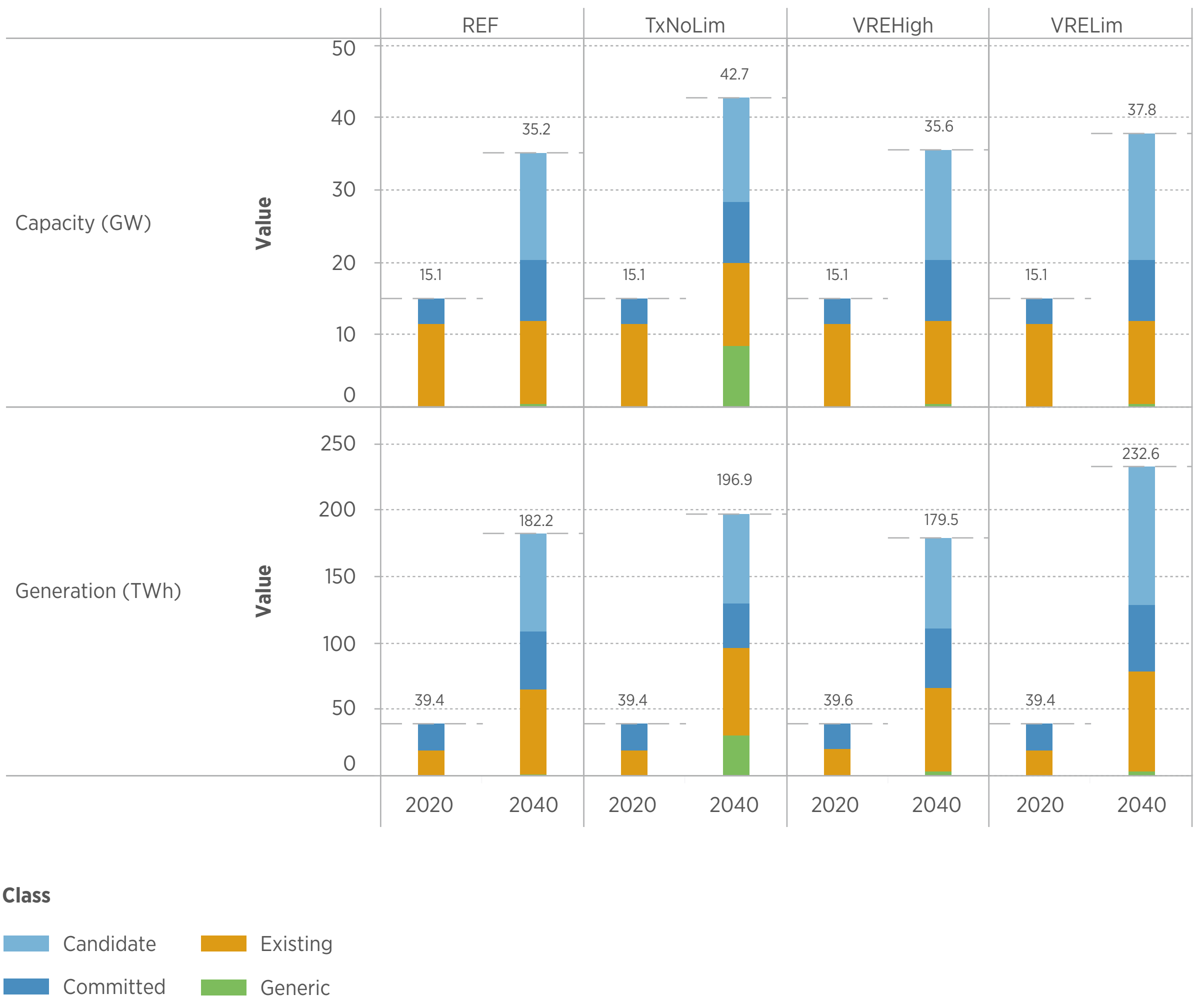


5.6 Cross-border trade is integral to minimising system cost

With increased transmission capacity over time and more routes to trade electricity, power generated from areas with high-quality and cost-effective renewable resources can be used more efficiently to meet demand needs in other areas. Total trade flows grow by 4.5 times – from 39 TWh in 2020 to 182 TWh in 2040 (Figure 5-17) – in the Reference Scenario. In addition to the committed transmission lines, another 15 GW of additional capacity from candidate transmission lines can accommodate 74 TWh of trade flows in 2040. The number of country pairs with interconnectors almost doubles, from 18 to 35. The savings from these efficiency gains exceed the estimated costs for transmission capacity expansion, and the average utilisation rate increases from 30% to 58% (total flows as a percentage of total possible flows in a year).

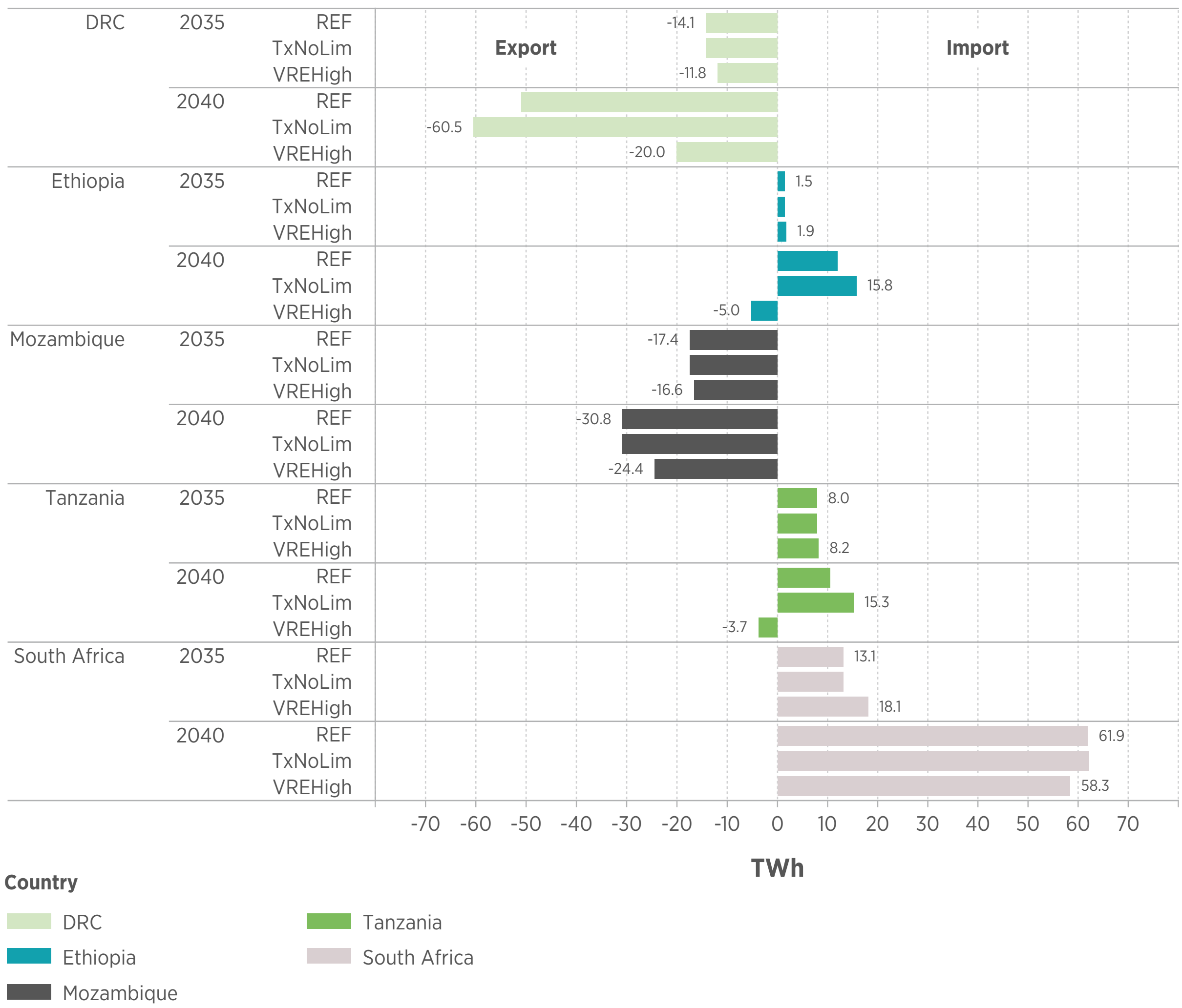
Across all scenarios, power trade increases to similarly significant levels relative to current levels. The VRELim scenario has the highest trade flows in 2040, with a utilisation rate of 71%, as countries exchange power with other countries to meet their demand needs if VRE deployment is limited. In the VREHigh scenario, total trade flows are also similar, since countries obtain an adequate supply of power from their domestic VRE sources.

Figure 5-17: Interconnector capacity (GW) and total trade flows (TWh) in 2020 and 2040 for four scenarios (REF, TxNoLim, VREHigh, VRELim)



Among certain countries, net trading volumes increase tremendously in the last five years of the horizon, between 2035 and 2040. Figure 5-18 shows a country-level breakdown of the net imports in 2035 and 2040 under the Reference scenario and the TxNoLim scenario for major trading countries. Under all scenarios, the largest net importer is South Africa (62 TWh in 2040 in the REF scenario). Significant exporters include the DRC (REF, 51 TWh; TxNoLim, 60 TWh) and Mozambique (REF and TxNoLim, 31 TWh) in 2040. When there is a higher level of VRE deployment (VREHigh), Ethiopia and Tanzania both become net exporters, while the DRC sees much lower net exports as compared to the REF scenario. While trade between individual countries can be sensitive to the level of VRE penetration, the increase in trade volumes over the years attest to its role in minimising the system costs of the entire region.

Figure 5-18: Net imports of electricity of major exporting (negative) and importing (positive) ACEC countries in 2035 and 2040 for the REF, VREHigh and TxNoLim scenarios



When more investment options are able to come online from 2030 (TxNoLim), 8 GW more generic transmission capacity than in the REF scenario is expected to host a total of 30 TWh of power flows in 2040. The additional capacity is for strengthening the link for Sudan–Ethiopia–Kenya and DRC–Tanzania–Malawi.

As these interconnectors are expanded, alongside generation infrastructure, the overall system cost can be reduced modestly by 1% as compared to the REF scenario. However, the impact at country level is more significant. Without considering export revenues,[51] at the country level, Ethiopia and Tanzania have most to gain, saving up to USD 1 billion (10%) and USD 480 million (7%) per year by 2040, respectively. For exporting countries which may see higher system costs, a further investigation may be conducted to understand how such costs can be offset by export revenues.

51 Export revenues are not considered as part of total system cost in this optimisation of the region, as one country's revenue is another country's cost.

Table 5-3 summarises the interconnectors' modelled capacities by 2040, together with the corresponding total trade volumes on the lines.[52] The values indicate the total volume traded along the line in both directions. There are increases in capacities in the REF scenario compared to the unconstrained[53] capacities in the TxNoLim scenario. Increased summed flows on some lines in the TxNoLim scenario also show that with greater interconnectivity, these lines need to be strengthened. In the VREHigh scenario, more power flows are expected on certain lines as compared to the REF scenario. However, the flow on the DRC–South Africa line is reduced, as the DRC's hydropower production from the Inga plants is outcompeted by VRE, despite its low VOM cost (USD 0.03/kWh) and it cannot export as much.

Table 5-3: Modelled interconnector capacities and total trade volumes between countries in 2040, sorted in order of total flows (REF scenario)

Interconnector (bi-directional)	Capacity (MW)			Trade flows (GWh)		
	REF	VREHigh	TxNoLim	REF	VREHigh	TxNoLim
DRC - South Africa	2 500	2 500	2 500	21 725	12 596	21 725
Angola - DRC	1 663	1 663	1 663	14 499	12 230	14 499
Ethiopia - Kenya	2 000	2 000	4 405	14 027	6 713	16 232
Botswana - Zimbabwe	2 030	2 030	2 030	12 865	9 651	12 976
Mozambique - Eswatini	1 613	1 613	1 613	12 614	12 549	12 614
South Africa - Eswatini	1 344	1 344	1 344	11 656	11 656	11 656
Botswana - South Africa	1 349	1 349	1 349	11 315	11 718	11 424
Mozambique - South Africa	2 586	2 586	2 586	10 779	13 631	10 896
Zambia - Zimbabwe	1 800	1 800	1 800	8 510	8 883	11 612
Egypt - Sudan	1 732	1 732	1 732	8 491	13 796	10 299
Burundi - DRC	748	748	748	6 083	3 001	3 391
Burundi - Tanzania	1 109	1 109	1 109	5 269	3 931	2 671
Namibia - South Africa	991	991	991	4 542	4 827	4 504
Malawi - Mozambique	1 800	1 800	1 800	4 532	1 013	3 931
Namibia - Zambia	650	650	650	4 117	5 560	4 240
DRC - Rwanda	713	240	744	3 660	1 396	3 785
Kenya - Tanzania	600	600	881	3 295	5 035	1 704
Ethiopia - Sudan	2 521	2 521	4 514	2 905	11 605	3 057
South Africa - Zimbabwe	500	500	500	2 860	4 344	2 921
Malawi - Zambia	1 355	1 395	736	2 613	3 048	1 182
Angola - Namibia	700	700	700	2 417	1 490	2 421
Mozambique - Zimbabwe	900	1 568	900	2 404	2 084	3 180

52 Total trade volume refers to the sum of flows on the line.

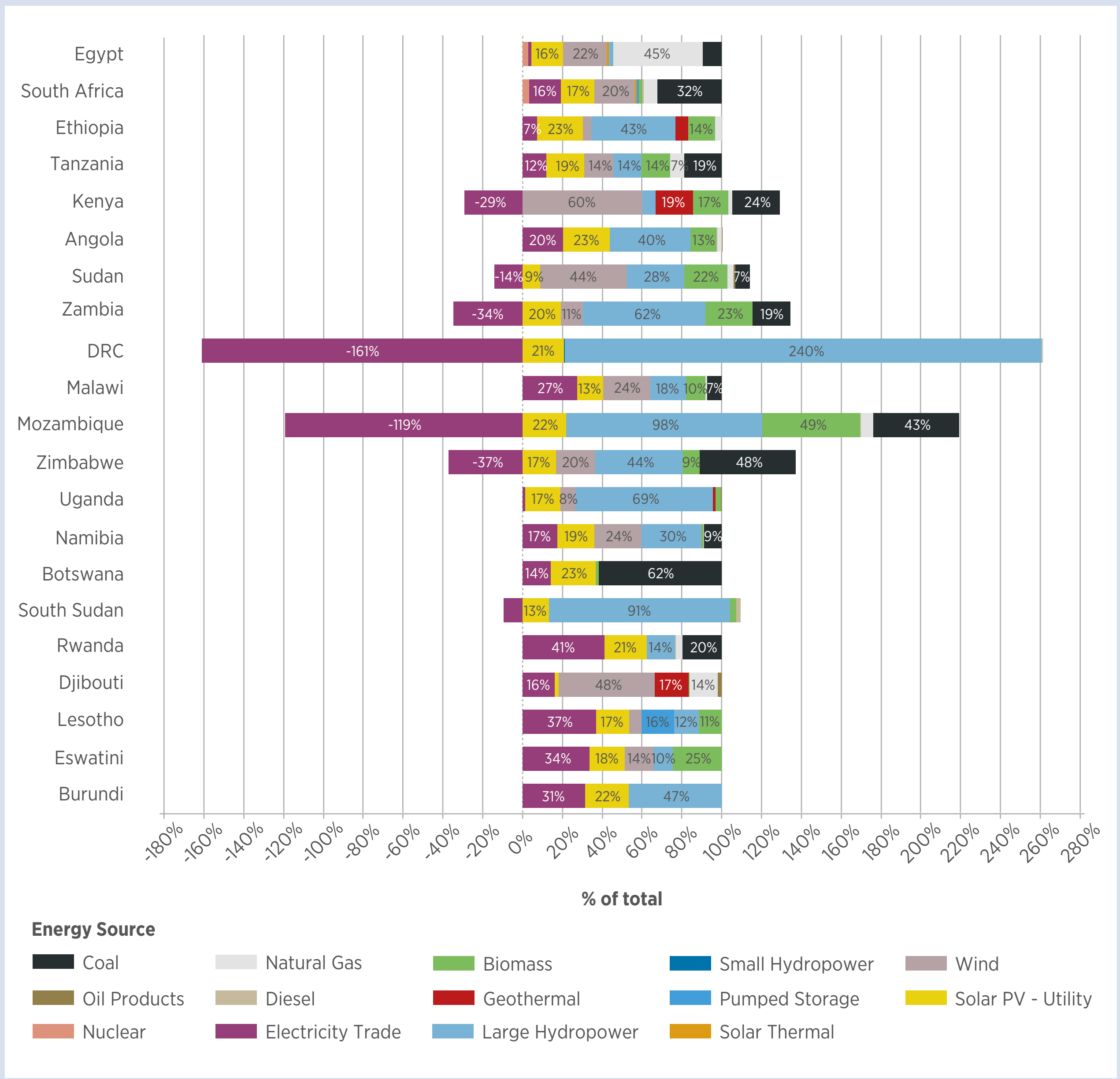
53 Unconstrained build capacity that was identified in the model results for a cost-optimal regional supply mix.

Interconnector (bi-directional)	Capacity (MW)			Trade flows (GWh)		
	REF	VREHigh	TxNoLim	REF	VREHigh	TxNoLim
Tanzania - Uganda	431	431	431	1 696	1 793	1 641
Lesotho - South Africa	217	217	217	1 457	981	1 468
Rwanda - Tanzania	181	181	181	1 415	1 072	1 445
Kenya - Uganda	400	400	400	1 097	3 332	1 245
DRC - Uganda	388	388	388	1 056	2 824	1 067
DRC - Zambia	120	120	120	1 042	125	1 042
South Sudan - Uganda	227	250	222	909	1 283	922
Mozambique - Tanzania	300	300	300	575	2 507	433
Tanzania - Zambia	750	750	750	483	1 436	268
Djibouti - Ethiopia	380	380	548	480	571	472
Rwanda - Uganda	363	363	363	389	1 908	458
South Sudan - Sudan	29	33	29	234	238	226
Mozambique - Zambia	200	200	200		49	18
Malawi - Tanzania			619			2 685
DRC - Tanzania			1 347			11 804
Burundi - Rwanda		127			412	

Note: the cells are colour coded by the magnitude of their differences from the Reference Scenario, with red indicating a reduction and green indicating an increase.

Figure 5-19 shows the share of electricity trade and power generation of each technology as percentages of domestic demand in 2040, by country. In a few countries, imports play an important role in meeting domestic demand. Trade meets more than 30% of domestic demand in Burundi (30%), Eswatini (34%), Lesotho (44%) and Rwanda (41%). Net exporters – the DRC and Mozambique – export more than 100% of their domestic demand. The generation mix across the two scenarios are similar for most countries, except for the DRC, which produces and exports 30% more hydropower when the build of interconnectors is unconstrained.

Figure 5-19: Share of generation and net imports relative to domestic demand in countries under the Reference scenario, 2040



5.7 Regional integration where synergies exist addresses the need for flexible generation

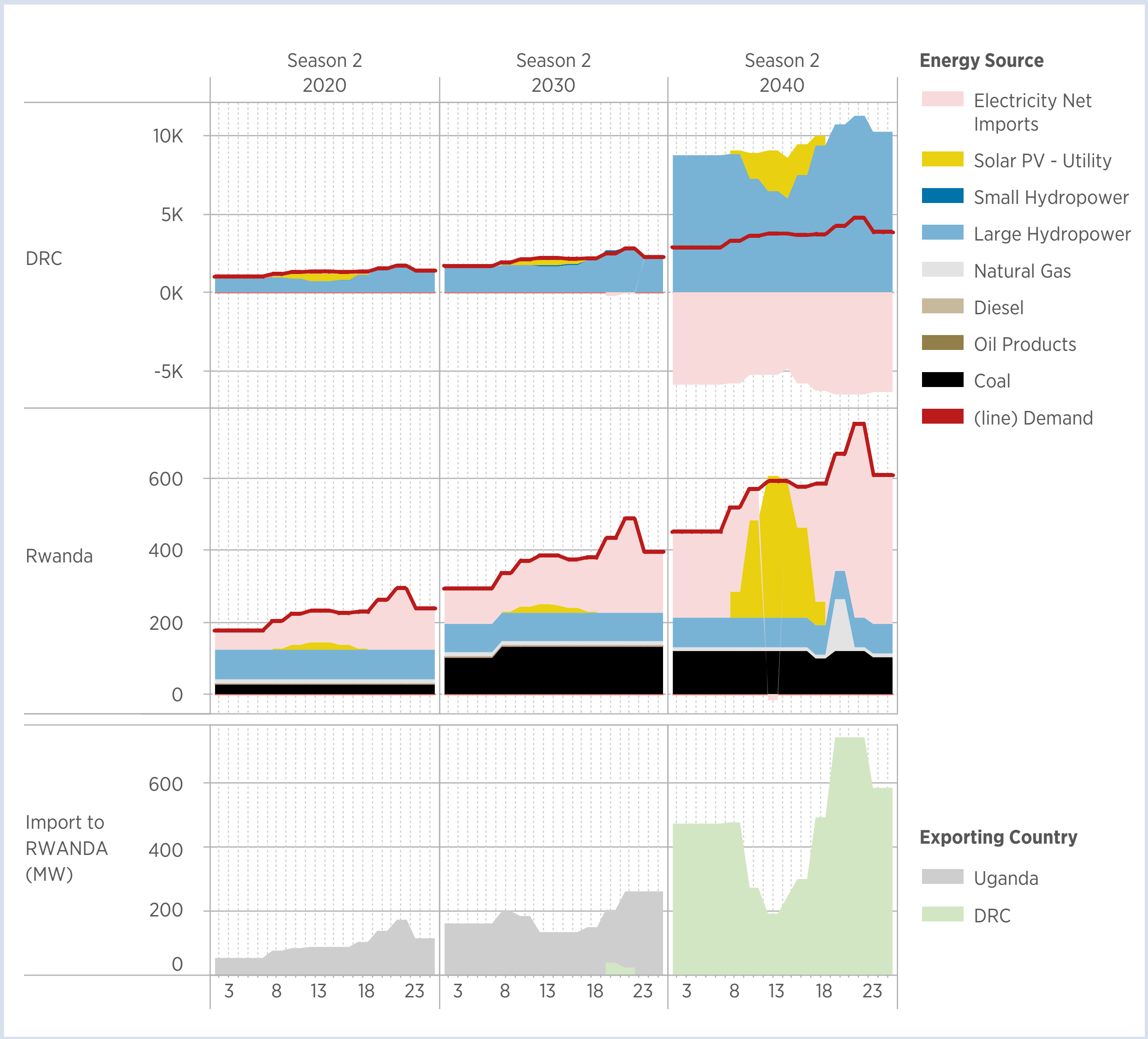
An increase in interconnector capacities not only enhances cost efficiency of production by facilitating the increased flow of lower-cost power supplies, it also enables the pooling (and mutual balancing) of supplies from resources with hourly fluctuating and complementary profiles. For example, hydropower supplies are flexible and can therefore help balance the inherent variability of VRE supplies. Complementary generation profiles between countries can be utilised to provide stable power through trade if there is adequate interconnector capacity. With adequate transmission infrastructure and generation capacity, a country with excellent hydro resources can import solar power during the day and export its hydropower at night. Furthermore, the time zone differences on the continent also mean that high demand periods occur at different times, possibly allowing one country to export to meet the peak demands of another, without putting excessive pressure on its own capacity margin.

One example that illustrates the enabling of cross-boundary synergies from increased transmission capacity is the interconnection between the DRC and Rwanda. Figure 5-20 shows the hourly production and transmission for both countries in 2020, 2030 and 2040 in the REF scenario, for season 2 (May–August). It also shows the hourly import by Rwanda. With increased transmission capacity over the years, high volumes of hydropower production at night can be exported to Rwanda, when there is a supply gap in Rwanda owing to the absence of domestic solar power generation.

Box 5-4: IRENA's FlexTool for flexibility assessments

Countries exploring ways to expand VRE in their power systems should conduct thorough flexibility assessments in addition to long-term capacity expansion analyses. Such assessments can dig deeper into the feasibility of results presented in this report to gauge when and where more specific flexibility measures can be implemented to support national capacity investment plans. IRENA provides a user-friendly FlexTool for precisely this purpose – FlexTool assessments reflect full power system dispatch and offer a detailed view of flexible generation options, demand flexibility and energy storage, along with sector-coupling technologies like power-to-heat, electric vehicles and hydrogen production through electrolysis. The IRENA FlexTool is currently the only publicly and freely available (open-source) tool of its kind, and can be found along with detailed training materials for use on the IRENA webpage.

Figure 5-20: Hourly generation and trade in the DRC and Rwanda for the Reference scenario in 2020, 2030 and 2040, in SAST (UTC+2:00).



By 2040, power production in the DRC grows beyond its domestic consumption. A large share of this excess electricity is generated from hydro resources to export to neighbouring countries. Specifically, under the Reference scenario, more than half of the DRC's power generation by 2040 is expected to be available for export. The expansion of transmission infrastructure from the DRC is key to enabling the export of excess electricity supply to the region.

On most transmission lines, the power flows in mostly one direction throughout the day, especially for large net exporters. On some lines, bi-directional flows occur (Figure 5-21) during the day and diurnal patterns are observed related to solar generation and evening demand peaks. In these cases, a country is exporting most of the time; during evening peaks, the trade flow changes direction, either to fulfil its domestic demand or to export the power to another neighbouring country (e.g. Uganda).

Figure 5-21: Hourly net exports on six power lines with significant bi-directional flows, 2040. Y-axis scaled according to magnitude, in SAST (UTC+2:00)

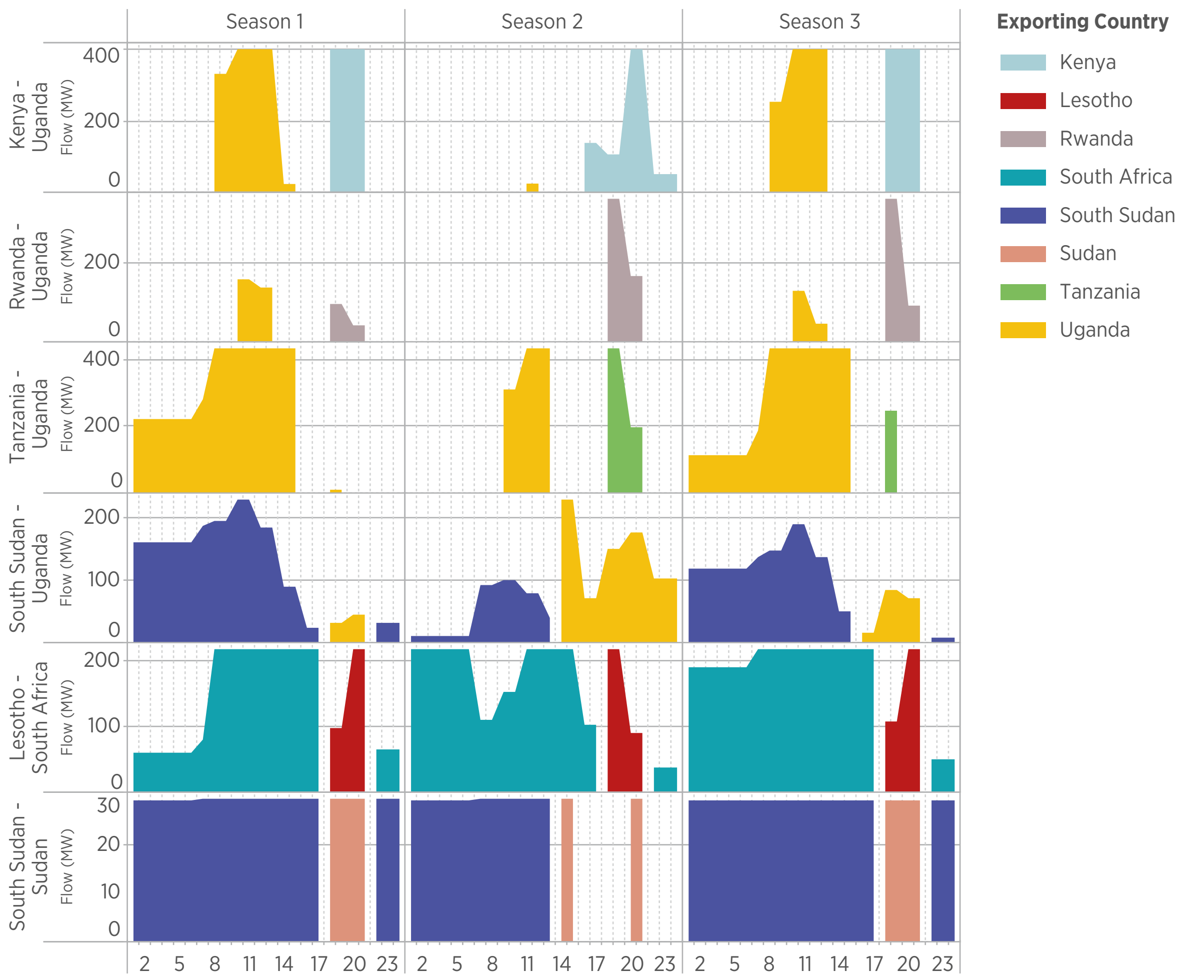
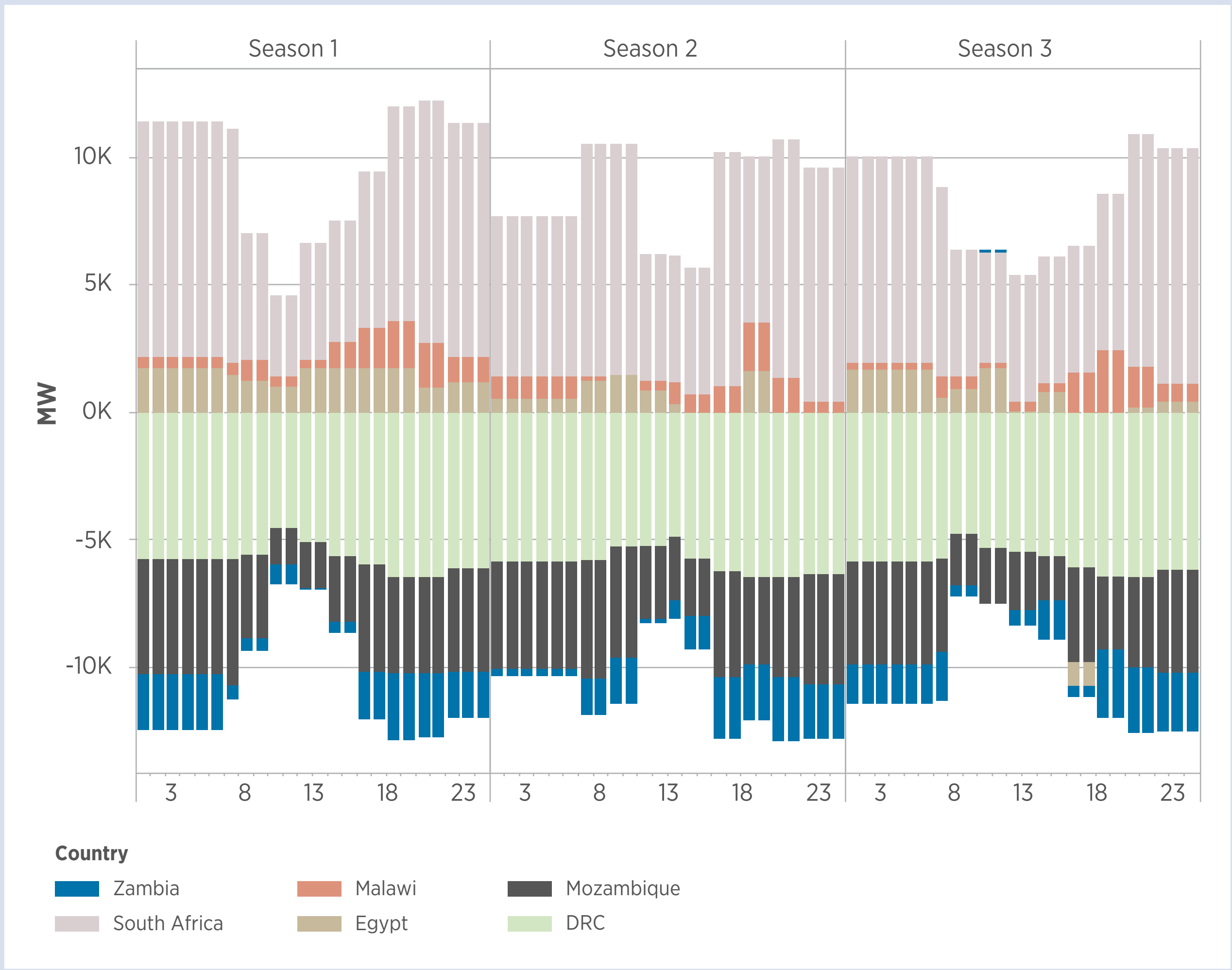


Figure 5-22 shows the hourly electricity imports of six countries of varying sizes, resource endowment and trading activities in the region across the three seasons in 2040 (see Section 4.2.2 for a definition of the seasons). As observed, the volume of trade during the day is lower than at night, indicating a strong correlation between solar PV production and trade levels. Countries that are net importers and have significant solar potential – such as South Africa – import less power during the day, when enough power is generated domestically from solar PV. With a higher uptake of renewables, trade activity becomes increasingly influenced by the generation pattern of variable renewables – especially solar PV. The effect of wind is also observed, to a lesser extent.

Figure 5-22: Daily electricity net imports of six selected ACEC countries for average days in the three seasons (2040), in SAST (UTC+2:00)



With high penetrations of solar PV and wind, power systems often face a greater need to provide flexibility, at hourly or sub-hourly timescales, to cope with the increased unpredictability caused by highly fluctuating supply from variable sources. Generally, if trade is limited, the need for flexibility is met by so-called "dispatchable" plants and/or storage facilities within each country. As Box 5-4 describes, however, a much wider range of power system flexibility solutions are becoming available to integrate higher shares of VRE.

While our analysis does not provide analysis on hourly or sub-hourly timescales, it suggests that with increasing regional integration through the expansion of interconnector capacities, inter-regional power trading can serve as one key source of flexibility. During demand peaks, imports of power from lower-cost renewable sources elsewhere can replace expensive domestic production from peaking plants. Also, imported electricity can be stored when low cost via pumped hydro and discharged later to meet demand needs.

For example, in Botswana, imported power is used to meet demand variability (e.g. demand spikes), such as in the evenings when production from solar PV is insufficient. The potential complementarity between hydropower supplies from the DRC and solar PV in Rwanda described in the earlier part of this section is another example on a hourly timescale. During periods of less sunshine, Rwanda can import hydropower from the DRC to meet its demand needs.

Box 5-5: The landscape of innovations for variable renewable power integration

While proper, long-term planning can address system flexibility by identifying complementary VRE profiles and opportunities for cross-border trade, many other innovations to integrate high VRE shares are also emerging and being implemented worldwide. IRENA's innovation landscape study has identified a suite of 30 such innovations across four key dimensions of the world's power systems:

- Enabling technologies: technologies that play a key role in facilitating the integration of renewable energy – such as batteries and renewable mini-grids.
- Business models: innovative models that create the business case for new services, enhancing system flexibility and incentivising further integration of renewable energy technologies – such as aggregators (through the use of blockchain), the advent of prosumers and community-ownership models.
- Market design: new market structures and changes in the regulatory framework to encourage flexibility and value services needed in a renewable-based power energy system, stimulating new business opportunities – such as time-of-use tariffs.
- System operation: innovative ways of operating the electricity system, allowing the integration of higher shares of variable renewable power generation – such as advanced VRE forecasting.

As VRE shares grow in a power system, combining innovations across these dimensions becomes key to unlocking synergies and reducing overall system costs. Not all innovations will necessarily be applicable immediately in the ACEC country context, and strategies to deploy particular sets of innovations are naturally country- and context-specific. Their benefits will depend on aspects such as the rate of electricity demand growth, the level of existing grid interconnectivity and the spread of domestic natural resources, among others.

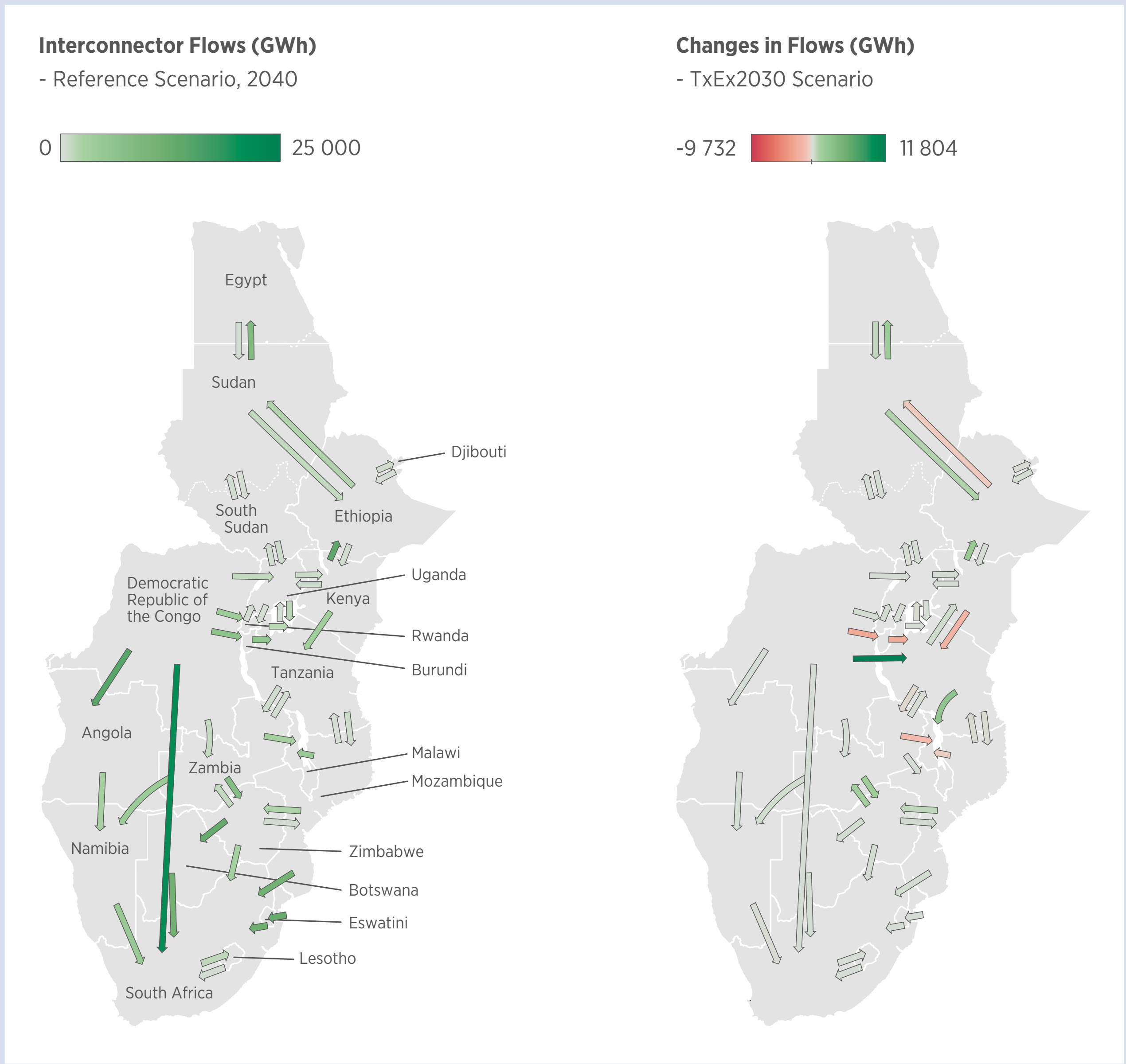
5.8 Modest potential for interconnection expansions beyond current plans

With the increase in total power flows between now and 2040 across all scenarios (Figure 5-17), existing and identified (committed and candidate) connections are adequate for increased power trade flows in the future. The TxNoLim scenario seeks to investigate how the system changes when additional interconnectors not yet considered (i.e. generic options) can come online from 2030. This scenario demonstrates that, beyond what has already been planned, there is even further potential along certain lines to accommodate higher trade flows.

Figure 5-23 shows the interconnector capacities in the region between 2020 and 2040 for the TxNoLim and Reference scenarios.

Flows between country pairs are shown together, with the difference in flows between the TxNoLim and the REF scenarios, are shown in Figure 5-23. The cost-effective potential for electricity trade among certain countries is suppressed if there are limits on transmission capacity expansions. Compared to the REF scenario, increases in trade flows are observed in the TxNoLim scenario between Kenya and Ethiopia, Egypt and Sudan, and Zambia and Zimbabwe. The transmission infrastructures between these countries have further potential for expansion beyond current plans. Relevant details can also be found in Section 6.3.

Figure 5-23: Cross-border transmission flows (GWh) in the region in 2040 for the REF scenario with only planned interconnectors (left) and flow changes with the TxNoLim scenario[54] and additional connections (right)



Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

54 The interconnection between the DRC and South Africa depicted on this map is a simplified view of the "power highway" that comprises a series of interconnectors from the DRC to South Africa, passing though neighbouring countries. There is a signed power purchase agreement between the two countries that commits South Africa to purchase 2 500 MW. A further agreement of 5 000 MW is in the process of being finalised (Clowes and Burkhardt, 2019).

5.9 Next steps

The zoning analysis and SPLAT model enable the quantification of system cost reductions from VRE deployment. They also allow analysts to perform analysis of hourly dispatch using seasonally averaged hours – at both country- and zone-levels – with the consideration of resource quality that can be zone-specific. IRENA has already sought validation from several stakeholders in the region with relevant activities (African Union, AUDA–NEPAD, GIZ, UNDP, etc.). The next steps will take into account further validation from the SAPP, EAPP, the Regional Economic Communities (RECs) and national policy planners. Building upon the work outlined in this report, the current analysis should serve as a basis for future work in the following areas:

- **The deployment of large-scale battery storage facilities and demand side response management can be explored** as a possibility in the context of rising VRE deployment.

- With expanding energy access and off-grid generation becoming increasingly relevant to the region, **combining the SPLAT-ACEC model with electrification models** can allow for the analysis of current electrification plans and reveal additional electrification needs.

- **Modelling improvements can be made to introduce more precision and detail to the analysis.** This can be done by including more time-slices, increasing the spatial resolution of transmission networks within country borders, decentralised generation, introducing operational constraints such as ramping rates for conventional power plants and modelling hydro storage plants in greater detail.

- **The zoning analysis and SPLAT model can also be extended to other regions**, such as the Central African Power Pool and the North Africa Power Pool, allowing for a holistic analysis of the resource potential on the continent.

- **Representing the trends of end-use sectors in demand.** Other renewable power generating technologies, as well as enabling technologies like renewable-power-to-hydrogen can be explored. Decentralised resources can also be investigated alongside utility-scale grid-connected renewables zones.

- **The impact on the power system from market mechanisms** such as power purchase agreements, auctions and feed-in tariffs can be further investigated.

- VRE integration requires more flexibility in current power systems, which calls for a paradigm shift. By combining innovations in enabling technologies (e.g. utility-scale batteries), business models (e.g. pay-as-you-go models), market design (e.g. regional markets) and system operation (e.g. virtual power lines), practical innovative solutions can be formed (e.g. demand-side management schemes). By working closely with countries, IRENA can explore tailor-made innovative solutions for specific power system contexts.

- **Assessment of possible environmental and social impacts** of construction of the generation and transmission capacity projects identified in Chapter 5. Environmental impact assessments are needed to verify the suitability of the projects identified. Such assessments are already being conducted in the sector for other energy sources, an example being the Strategic Environmental Assessments by IAEA for nuclear energy (International Atomic Energy Agency, 2018), from which planners of solar PV and wind projects can derive lessons.

PART III:

INFRASTRUCTURE INVESTMENT PROJECTS OF PARTICULAR INTEREST FOR THE PIDA PROCESS

Part III of this report comprises a single chapter.

Chapter 6 focuses on the identification of two particular types of infrastructure investments identified as attractive in this report's analysis: generation projects that demonstrate good resource potential; and transboundary infrastructure projects that facilitate power transfer along the corridor. Discussion of these investments in the chapter may serve to highlight them for consideration in regional and continental infrastructure planning processes, such as the Programme for Infrastructure Development in Africa (PIDA).

INFRASTRUCTURE INVESTMENT PROJECTS OF PARTICULAR INTEREST

6

6.1 PIDA – a key continental infrastructure planning programme

While the results of this report's analysis provide important insights for power systems as a whole in the region, they can also deliver a wealth of information on the prospects and performance of particular projects. Such information can be useful to both public and private initiatives that are interested in infrastructure project development. Many such initiatives exist to spur the development of energy infrastructure in Africa, with one key effort led through the Programme for Infrastructure Development in Africa (PIDA) under the African Union Commission (AUC).

According to the AUC, the PIDA is a strategic framework running to 2040, with the buy-in of all African countries, to develop continental-scale infrastructure projects – including energy infrastructure – and strengthen the consensus and ownership around those projects (PIDA, 2017). An important element in this process is the PIDA's Priority Action Plans (PAPs), which identify specific projects for priority investment in the short-term.

The current PIDA PAP (2012–2020) outlines 433 projects (including 54 energy sector projects) for implementation in the short term, none of which are VRE generation projects. The PIDA PAP has been reviewed through the PIDA 'mid-term review' process that identified lessons learned and recommendations to accelerate implementation until 2020 and provide some inputs for the next phase of PIDA (PIDA PAP2 II) (NTU International A/S, 2019). This follow up, the PIDA PAP II, will provide a list of priority projects for the medium term – from 2021 to 2030.

One particular aim for PIDA PAP II will be to strengthen the role of VRE in the project list. This is, amongst others, reflected in the objectives of the *PIDA Market & Demand Study*, which state: "Renewable energy technologies have advanced and become competitive, also on a regional scale, and hence need to be integrated in a future PIDA master plan" (PIDA, 2019). The inclusion of VRE in such a large-scale programme reflects the fact that wind and solar have grown to be attractive options for bulk power systems, not only at the national level but at a regional level as well. With adequate cross-border infrastructure and environmental regulation in place, large wind and solar power projects can act as regionally beneficial resources in the same way that large hydro has done already.

Based on the scenario analysis presented in this report, this chapter therefore discusses examples of generation and transmission infrastructure projects that could be of regional interest to policymakers or others involved in future development programmes.

6.2 Power generation projects

This section identifies solar PV and wind power generation project zones in the region that could be of particular interest as large-scale infrastructure investment options.

As outlined in Chapter 3, 'zones' refer to land areas with associated resource quality and cost estimates. While there can be various interpretations of what makes a zone 'attractive' – e.g. on a pure cost basis, a job creation basis etc. – the discussion here focuses on top-ranking VRE zones from a technical and cost perspective, based on an initial set of three simple criteria in the modelling results:[55]

1) robustness – i.e. capacity contribution across all scenarios;

2) generation – i.e. production rank in the Reference scenario in 2030 and 2040; and

3) contribution to security of supply – i.e. supply contribution during hours of high domestic demand.

Box 6-1: Available instruments for project implementation

<u>Site appraisals</u>

Site appraisals are often conducted to establish the viability of prospective sites. The IRENA **site appraisal service** is an innovative and cost-effective approach to screen sites earmarked for solar and wind development in countries. It efficiently expedites the development process and increases the likelihood of success in finding economically viable sites for further investments. The service uses site-specific solar or wind resource profiles, a robust power generation model developed by IRENA, and a simplified financial model, which combine to establish the range of tariffs and levelised costs within which a specific site is likely to be developed.

<u>Project facilitation</u>

IRENA's **Climate Investment Platform** provides comprehensive and practical information, tools and guidance to assist project stakeholders in developing bankable renewable energy projects. Through the platform, technical concept guidelines that outline best practices are shared. Tools such as financial models, checklists and evaluation forms are also available. These tools enable developers to manage project progress, evaluate gaps and structure project proposals.

<u>Financing</u>

The **Climate Investment Platform** also connects project owners, financiers/investors, governments, service providers and technology suppliers. Project developers can access relevant funding sources and expertise to advance their projects.

The **IRENA/ADFD Project Facility** is a joint financing facility dedicated to financing renewable energy projects recommended by IRENA in developing countries.

55 For more detail on the zone ranking process behind the discussion here, see Appendix 7.9. It is important to note that the metrics for zone performance discussed here are based on the underlying assumptions that drive the SPLAT model's outcome, such as: resource availability; regional socio-economic developments; power generation; and investment costs. The criteria do not include considerations of environmental impact, inter-regional conflict etc., which can also be important factors in assessing suitability. These factors must be carefully evaluated for developing projects in any of the suggested zones, for instance through an environmental impact assessment (EIA). The discussions in this report on generation and transmission infrastructure projects should therefore be carefully checked in the context of these assumptions and limitations.

Upon identification, the chosen zones also show, to varying degrees, other desirable attributes such as low investment cost and co-location with other resources.

It should be noted that, once zones have been identified, the successful implementation of renewable energy projects comprises many phases. For reference, Box 6-1 identifies a range of available IRENA instruments to address the evaluation, financing and development of generation projects at sites of interest, at various stages of project implementation. It would also be useful to develop a further, large ensemble of sensitivities runs on parameters such as technology costs, discount rates and operational constraints to understand the robustness of the projects.

6.2.1 Top-producing project zones

This section presents the ranking of the top zones by generation in 2030 and 2040. Across six countries, the top zones amount to 38 GW and 42 GW of capacity, respectively in 2030 and 2040. This represents the zones in the highest 30 percentiles in both 2030 and 2040 under the Reference scenario. A list of these 24 zones is summarised in Table 6-1.[56] The project zones with the highest projected power generation are located mainly in South Africa and Egypt. The top producing projects include a wind project (FY) in east Egypt and two solar projects (AR and V) in the west of South Africa. These projects would be cost-effective to build in the next decade. The main characteristics of each zone are discussed in Section 6.2.3.

56 Zone names follow the convention used in IRENA's MapRE study.

Table 6-1: Top 24 generation zones ranked by estimated annual production volume (in GWh) in 2030 and 2040

Zone	Country Name	Technology Type	Longitude	Latitude	First Year	Generation (TWh)		Capacity Factor		Capacity (MW)	
						2030	2040	2030	2040	2030	2040
AR	South Africa	Solar PV - Utility PP	18.139.048	-29.650.713	2028	12 787	12 787	0.25	0.25	5 830	5 830
FY	Egypt	Wind PP	33.085.860	28.220.497	2025	8 737	8 737	0.43	0.43	2 340	2 340
AO	South Africa	Solar PV - Utility PP	18.820.220	-29.191.607	2015	6 944	6 241	0.25	0.22	3 200	3 200
V	South Africa	Solar PV - Utility PP	24.615.902	-27.187.761	2015	6 032	8 424	0.24	0.24	2 828	3 950
GU	South Africa	Wind PP	26.294.913	-32.557.929	2027	5 808	5 808	0.37	0.37	1 780	1 780
CO	Sudan	Wind PP	36.870.124	21.789.527	2026	5 530	5 795	0.41	0.40	1 555	1 650
FR	Egypt	Wind PP	32.996.457	27.906.896	2026	5 374	5 374	0.40	0.40	1 540	1 540
FU	Egypt	Wind PP	32.914.229	28.292.336	2026	5 185	5 185	0.40	0.40	1 470	1 470
GX	South Africa	Wind PP	25.898.351	-32.955.934	2015	4 767	4 767	0.38	0.38	1 450	1 450
BI	South Africa	Wind PP	22.749.424	-32.092.741	2028	4 686	4 686	0.35	0.35	1 520	1 520
AA	Egypt	Wind PP	32.564.977	25.860.225	2017	4 350	4 350	0.33	0.33	1 510	1 510
FQ	Egypt	Wind PP	33.492.133	27.773.982	2026	3 933	3 933	0.40	0.40	1 110	1 110
DM	Kenya	Wind PP	36.733.742	2.313.020	2026	3 748	3 710	0.49	0.49	872	872
CT	South Africa	Wind PP	22.690.563	-32.195.163	2015	3 725	3 618	0.35	0.34	1 200	1 200
IA	Egypt	Wind PP	33.173.004	29.190.783	2027	3 711	3 711	0.39	0.39	1 100	1 100
EZ	Kenya	Wind PP	37.560.469	3.427.129	2025	3 488	3 431	0.59	0.58	675	675
GW	Egypt	Wind PP	32.464.060	29.144.520	2027	3 240	3 240	0.40	0.40	926	926
FZ	Egypt	Wind PP	32.933.159	28.326.220	2025	2 952	2 952	0.42	0.42	804	804
EF	Egypt	Wind PP	33.674.468	27.395.599	2028	2 803	2 803	0.38	0.38	845	845
AT	South Africa	Solar PV- Utility PP	18.975.677	-29.586.296	2027	2 788	2 788	0.25	0.25	1 280	1 280
AF	Tanzania	Solar PV - Utility PP	33.101.278	-3.878.719	2021	2 732	7 043	0.26	0.26	1 198	3 090
CO	Ethiopia	Solar PV - Utility PP	38.974.699	12.997.411	2027	2 721	2 721	0.26	0.26	1 180	1 180
FS	Egypt	Wind PP	32.894.786	28.413.101	2027	2 652	2 652	0.40	0.40	750	750
IC	Sudan	Solar PV - Utility PP	22.485.561	13.178.308	2026	2 428	4 858	0.26	0.26	1 079	2 160

6.2.2 Top contributors to meeting domestic demand peaks

While a zone's overall generation can be a valuable metric, especially with cross-border power trade helping to meet demand in the region, its role in fulfilling domestic electricity need is also an important consideration in many contexts. In this section, the amount a project is modelled to produce at peak demand periods is used as a proxy to estimate its relevance corresponding to the domestic demand pattern.

During model optimisation, costs to the system – including generation by other technologies – affect the overall economic viability of the projects. This analysis goes a step further than a simple matching of generation and load profiles without models, which would not identify the optimal capacity of the projects. Among those projects that are deemed viable (i.e. built) in the model for the Reference Scenario, a project's power production during the top 10% demand hours in respective countries is used as a metric for the project's value in meeting domestic power needs.

Figure 6-1 shows 24 shortlisted zones' individual contributions to fulfilling domestic demand during the top 10% of demand hours. A high percentage indicates that a zone can meet most of the demand during peak demand hours, thus corresponding well to domestic needs (for example, 100% means that a zone, alone, meets all the power demand during the top 10% demand hours). A time frame to 2030 is used as reference for consistency with the time frame of PIDA PAP II. The size of the marks denotes the total demand during those peak demand hours.

Two project zones situated in Sudan and a further two in western Kenya are the top performers under this criterion. In South Africa, there are three project zones well suited to meeting domestic demand, which also rank highly in total generation.

Box 6-2: Other zones with significant production

Countries such as South Africa and Egypt are seen to have the largest projects, partly because these two countries can support bigger projects given their large domestic demand. In order to offer a more comprehensive picture of the zones, this report also identified a number of zones that constitute a high share of total domestic production in 2030. Although these zones are mostly not part of the nine analysed in detail, they can be of interest to those who wish to deep-dive into zones that are significant on a national scale. The table below shows the zones that produce more than 5% of total national output in 2030 in the Reference scenario.

Country Name	Technology Type	Zone	
Sudan	Solar PV - Utility PP	IC	7%
	Wind PP	CO	15%
Tanzania	Solar PV - Utility PP	AF	7%
Namibia	Solar PV - Utility PP	AL	22%
Malawi	Wind PP	Q	6%
Lesotho	Solar PV - Utility PP	J	31%
Kenya	Wind PP	DM	7%
		EZ	7%
Djibouti	Wind PP	E	46%

Figure 6-1: Share of zone production contributing to the top 10% demand hours in 2030

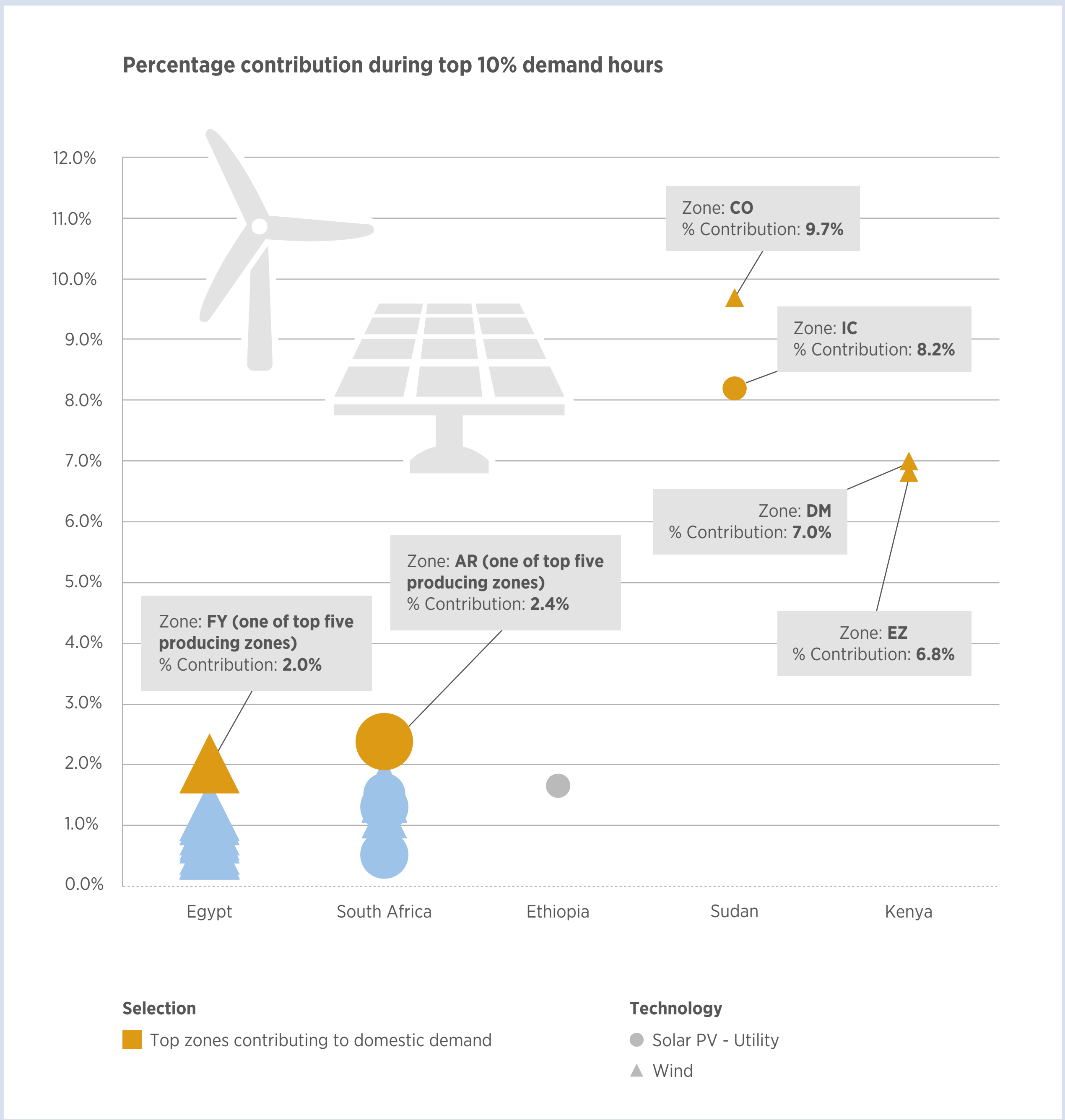
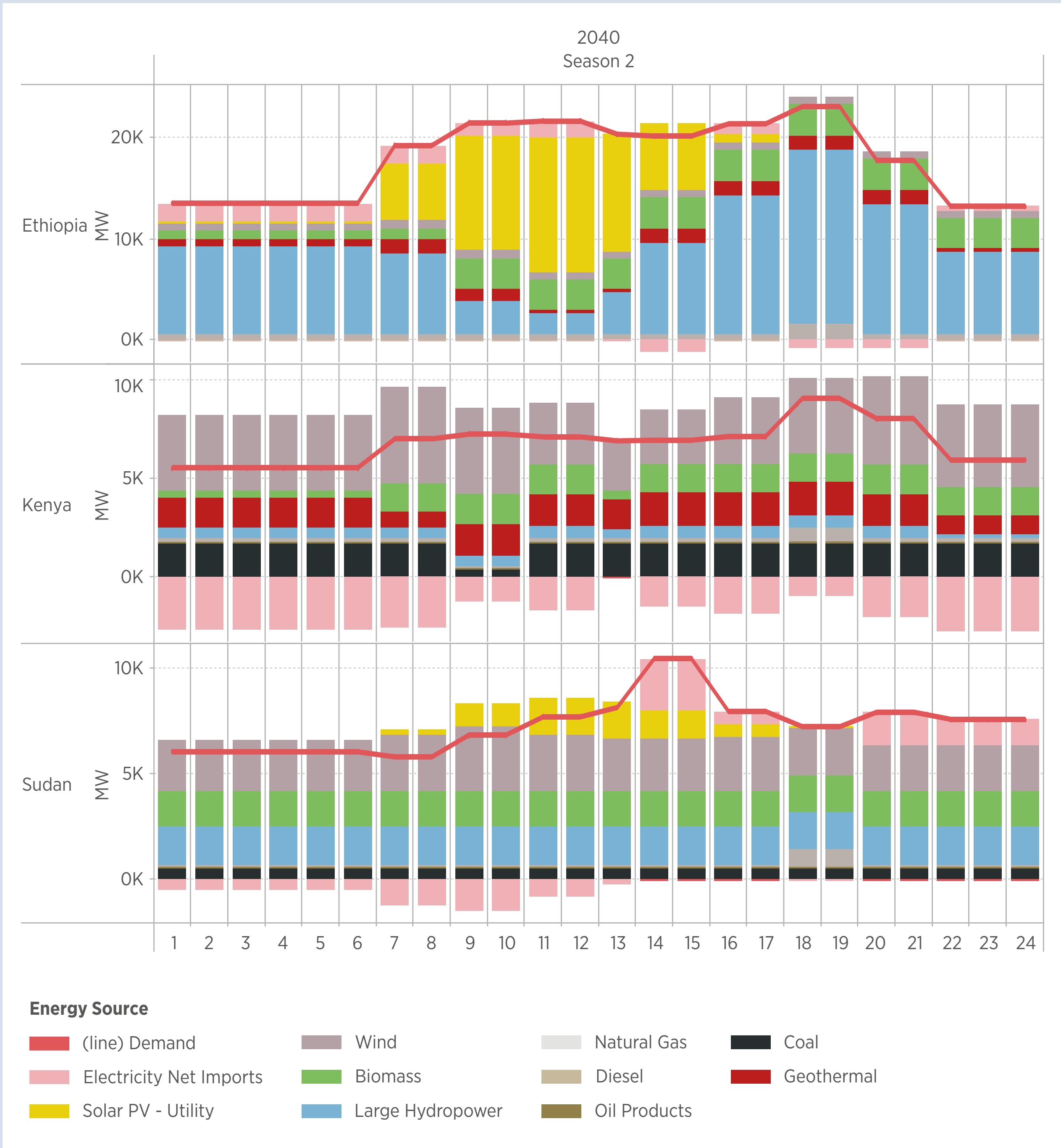


Figure 6-2 presents the generation mix of Ethiopia, Kenya and Sudan in 2030, giving an idea of their potential VRE resource contributions during peak hours. Solar penetration is significant in Ethiopia, as is wind in Kenya and Sudan.

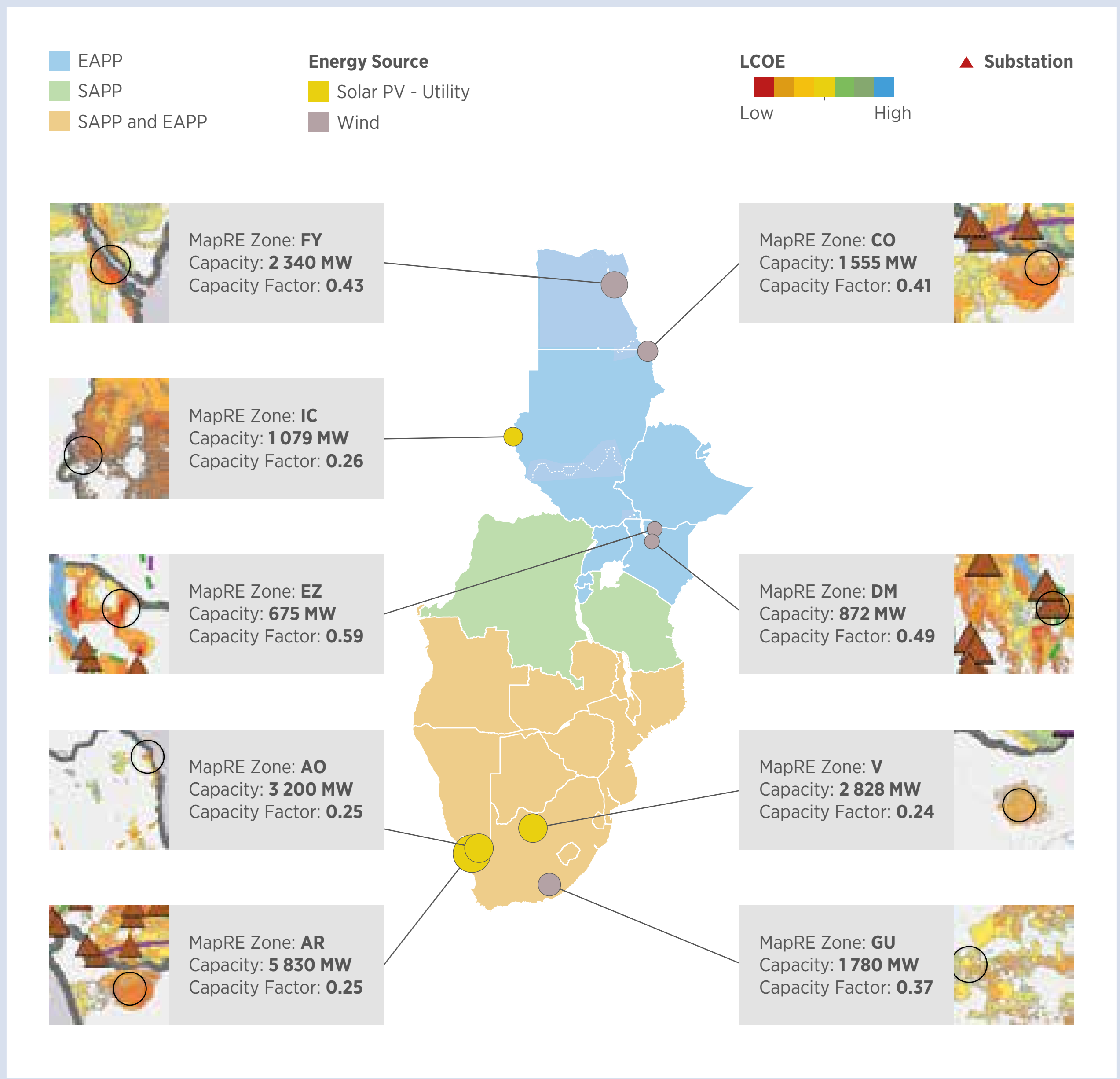
Figure 6-2: Generation mix for Ethiopia, Kenya and Sudan, 2040, season 2, over 24 hours, in SAST (UTC+2:00)



6.2.3 High potential projects

Based on their desirable attributes assessed by the two criteria – high generation and level of contribution to the top 10% of demand hours – in this section we discuss some of the selected zones. These zones serve as examples of potential projects for consideration under the PIDA PAP II process. Figure 6-3 shows a summary of these zones, their locations and their LCOE relative to other zones. This section elaborates on their characteristics in detail.

Figure 6-3: Nine specific zones for generation capacity expansion are selected for consideration under the PIDA process[57]



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57 These LCOE figures are inclusive of non-generation components and estimated with MapRE methodology.

6.2.3.1 South Africa – zones AR, AO & V (solar PV)

The zones AR and AO are located in the western part of South Africa, while zone V is in the north. The three zones feature high solar irradiance and the highest projected generation by 2030 of all solar PV zones modelled for this study (12 787 GWh, 6 944 GWh and 6 032 GWh, respectively). The large land sizes of the zones (zone AR, 1 943 km^2; zone V, 1 316 km^2; and zone AO, 1 066 km^2) enable the installation of large PV power plants. Zones AO and AR are characterized by a capacity factor of 0.25, and zone V of 0.24.

From the model results, the capacities of these zones are 5 830 MW in zone AR, 3 200 MW in Zone AO, and 2 828 MW in zone V. The attractiveness of these zones is borne out by reality to some extent, as some existing solar PV projects are already built in these locations – a capacity of 243 MW is installed in zone AO, and 180 MW in zone V. [58] The projects also perform well in meeting domestic peak demand, meeting 5.6% of total demand during top demand hours (2.4%, 1.7% and 1.5%, respectively).

The three zones are also located close to South Africa's borders with Botswana and Namibia. This geographical proximity to neighbouring countries provides opportunities for cross-border exchange.

Long-distance interconnectors will also play a role in distributing the power produced from diverse energy sources in the ACEC region. Given South Africa's potential interconnection with the DRC, complementary power generation patterns from solar PV in South Africa and hydropower in the DRC can be utilised to provide stable power in the region, to a greater extent than if the resources were isolated. In the modelling behind this report, the development of these zones is an important step toward realising the long-term potential for complementary hydro and solar PV generation through power trade.

6.2.3.2 Egypt – zone FY (wind)

This project zone in the north east of Egypt has the highest projected wind generation (8 737 GWh) by 2030. The encompassed area is quite large, covering 1 042 km^2. The zone also boasts high wind speeds (7.1 m/s at 50 m)[59] and features an exceptionally high estimated capacity factor (0.43) for onshore wind technology. The overall capacity of this zone from the model is 2 340 MW. Developing a project of this capacity can make a considerable contribution to meeting domestic demand in Egypt, increasing the value of Sudan's hydropower resource to provide flexibility, or even allowing the prospect of exporting Egyptian wind power through Sudan to other large load centres during evening peak times. The project is also capable of meeting 2% of domestic demand during peak hours. These different factors, in principle, make it an attractive project option for onshore wind technology.

6.2.3.3 South Africa – zone GU (wind)

The zone covers an area of 792 km^2 in the southern area of South Africa with a projected generation in 2030 of 5 808 GWh. The average wind speed in the region is around 5.9 m/s (at 50 m)[60], and the zone has an average capacity factor of 0.37. The total capacity was 1 780 MW, and as the largest wind zone in South Africa of such quality, it represents a significant investment opportunity to diversify the power infrastructure of the country and the region.

6.2.3.4 Sudan – zones IC (solar PV) & CO (wind)

From the model results, wind project zone CO in Sudan has an optimal capacity of 1 555 MW in 2030, which will contribute to meeting 9.7% of the country's power demand during peak hours, representing the highest proportion among the zones selected in this report. This indicates a key role in ensuring security of supply in Sudan. The project also performs well in the previous section's metric of overall generation, as the 6th highest generating project (5 530 GWh) in the

58 According to IRENA's plant database at the time of this report's writing.

59 Simulated average wind speed from 1985 to 2017 by Vortex (Vortex, n.d.).

60 Simulated average wind speed from 1985 to 2017 by Vortex.

entire region. The zone features a capacity factor (41%) higher than the average of modelled wind zones (34%), and the wind speed (5.9 m/s at 50m) makes this zone suitable to deploy the IEC class 3 turbine.

During peak demand hours in 2030, solar PV zone IC in Sudan is modelled to generate 8.2% of domestic power needs. The zone has an estimated capacity factor of 26%, which is higher than the average of modelled solar PV zones (24%).

6.2.3.5 Kenya – zones DM & EZ (wind)

Wind project zones DM and EZ, in Kenya, offer the potential to produce the equivalent of 7% and 6.8% of domestic demand, respectively, during the top power demand hours in 2030. In 2030, model results also envisage Kenya as an exporter of electricity to Ethiopia and Uganda, even during periods of high domestic demand, based on the surplus power that is produced at low cost from such wind resources. In this sense, these zones also have the potential to contribute to security of supply at the regional level, if adequate interconnection is developed. The zones have high capacity factors (49% for zone DM and 59% for zone EZ) and high average wind speeds (7 m/s and 8.8 m/s at 50 m). IEC class 1 and class 3 turbines are suitable for wind generation projects at these two locations, respectively. These factors make the wind zones suitable for generation capacity expansion.

6.3 Transmission projects

Increasing the share of VRE generation through the projects described above will also give regional trade a more important role – in providing back-up power, realising regional synergies and efficiently distributing surplus power generated from VRE sources. Increased interconnection can thus lower overall system costs, as outlined in Section 5.6 above.

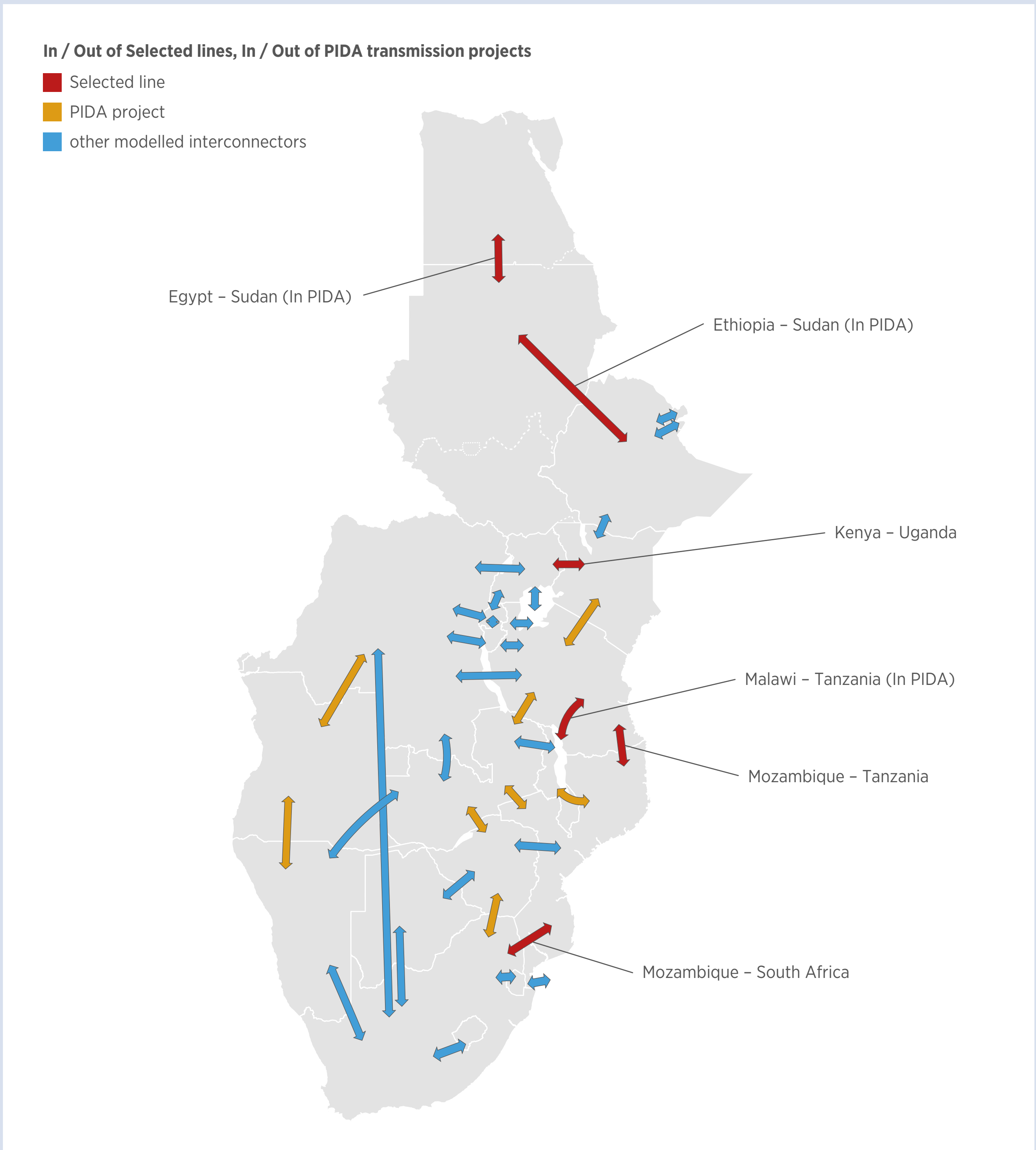
By analysing the expected long-term transmission expansions and trade flows in the Reference, high renewables and unconstrained build scenarios, this report reveals the advantages of strengthening interconnectors to maximise the benefits of regional power system integration. Figure 6-4 shows six key interconnectors (in red) that could be strengthened or expanded, among all modelled interconnectors in the region. Interconnectors that are already identified as PIDA projects are coloured orange. These suggested interconnectors would contribute to 1) reducing system cost and 2) facilitating the transfer of electricity at levels of high VRE deployment – or both.

In addition to the generation projects described in Section 6.2, the inclusion of these six identified interconnections in regional infrastructure development initiatives like the PIDA PAP II could further leverage the benefits of VRE generation and harness opportunities for increasing system flexibility through trade (see Section 5.7). Currently, 26 interconnector projects under PIDA PAP I are in various stages of development in the region[61] (a complete list of these projects is included in the Appendix) and four of the six projects discussed here are already identified as PIDA projects (Egypt–Sudan, Ethiopia–Sudan, Malawi– Tanzania, and Zambia–Zimbabwe).

As with the suggestions of generation capacity projects in Section 6.2, this analysis is dependent on the assumptions in the model. The expansions of interconnectors in the model are mainly driven by the cost of transmission lines and the electricity cost differentials between countries, among other factors. They are limited by the available options described in 4.3.4. Any transmission capacity development or expansion projects would need to involve an assessment of other relevant factors (including their impacts on the environment and land use). The following sections will expand on the transmission projects and explain their merits based on model results.

61 The PIDA project dashboard (PIDA, 2020) contains details on the projects under PIDA.

Figure 6-4: All interconnectors modelled in the region, with those identified in the PIDA in orange and interconnectors with high potential as identified in this report in red



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6.3.1 Egypt–Sudan

From modelling results, transmission flows between Egypt and Sudan in 2040 are seen to be significantly higher in both the VREHigh (13 795 GWh) and TxNoLim (10 299 GWh) scenarios, as compared to the Reference scenario (8 491 GWh). This indicates that strengthening this interconnector will be economically beneficial, with higher regional deployment of VRE, especially in a situation where the interconnector is allowed to grow to optimal levels beyond 2030.

Figure 6-5 shows the modelled hourly production in Egypt and Sudan, as well as the flows on the Egypt–Sudan line, in the REF and TxNoLim scenarios. In the TxNoLim scenario, there is an increase in the number of hours where the flow of electricity from Sudan to Egypt is at maximum capacity (1 732 MW). Increased flows occur especially during morning and afternoon, showing the interconnector is particularly valuable for exploiting additional Sudanese wind, solar and hydropower that can be economically exported.

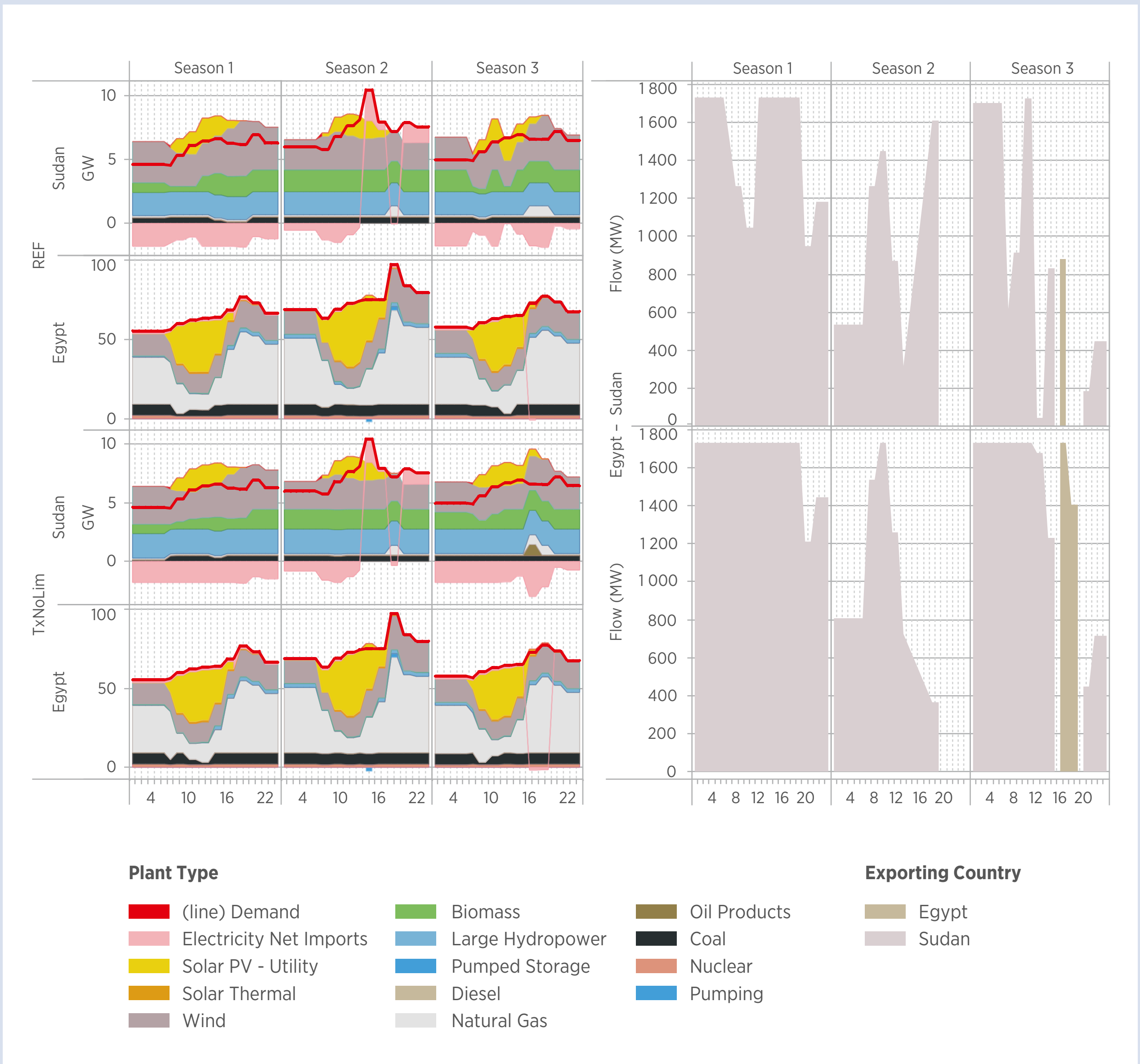
In April 2020, the Egypt–Sudan joint grid officially commenced operation, with the first stage of electric interconnection with Sudan through which Egypt provides up to 70 MW of capacities (Ahram Online, 2020). Further, an Egypt–Sudan transmission interconnector is currently already identified as a PIDA project. This project is under the North–South Power Transmission Corridor Programme and involves the construction of a 500 kV interconnection line of 1 000 MW capacity (PIDA, 2020).

6.3.2 Ethiopia–Sudan

In the TxNoLim scenario, where more interconnectors can be built from 2030, an additional 2 002 MW of interconnector capacity between Ethiopia and Sudan is observed in 2040. The expansion reduces overall regional system cost. In the VREHigh scenario, total flows on the line increase from 2 905 GWh (REF) to 11 605 GWh. This is particularly due to expanded buildout of wind power in Ethiopia, part of which can be economically exported to neighbouring countries with a strengthening of the interconnector.

This result supports existing development plans, as an Ethiopia–Sudan transmission interconnector is identified as a PIDA project at the Project Structuring Stage. This project is under the North–South Power Transmission Corridor Programme and involves the construction of a 500 kV interconnection line of 4 000 MW capacity (PIDA, 2020).

Figure 6-5: Modelled hourly production in Egypt and Sudan (left) with modelled flows on the Egypt–Sudan interconnector (right) in 2040, for REF and TxNoLim scenarios, in SAST (UTC+2:00)



6.3.3 Malawi–Tanzania

Figure 6-6 shows the modelled hourly imports of Malawi and Tanzania. In the TxNoLim scenario, in which transmission is able to expand beyond 2030, Tanzania is a transit country for the hydropower generated from the DRC.[62] With the onset of potential trade flows (2 685 GWh), a corresponding expansion of transboundary transmission capacity between Malawi and Tanzania is required (to 619 MW by 2040) to allow those flows to continue further on to Mozambique, for example. In the TxNoLim scenario, exports from Tanzania to Malawi therefore displace a portion of power flows from Zambia to Malawi.

A Malawi–Tanzania transmission interconnector is identified as a PIDA project at the 'project definition' stage. This project is under the North–South Power Transmission Corridor Programme and involves the construction of a 400 kV interconnection line (PIDA, 2020).

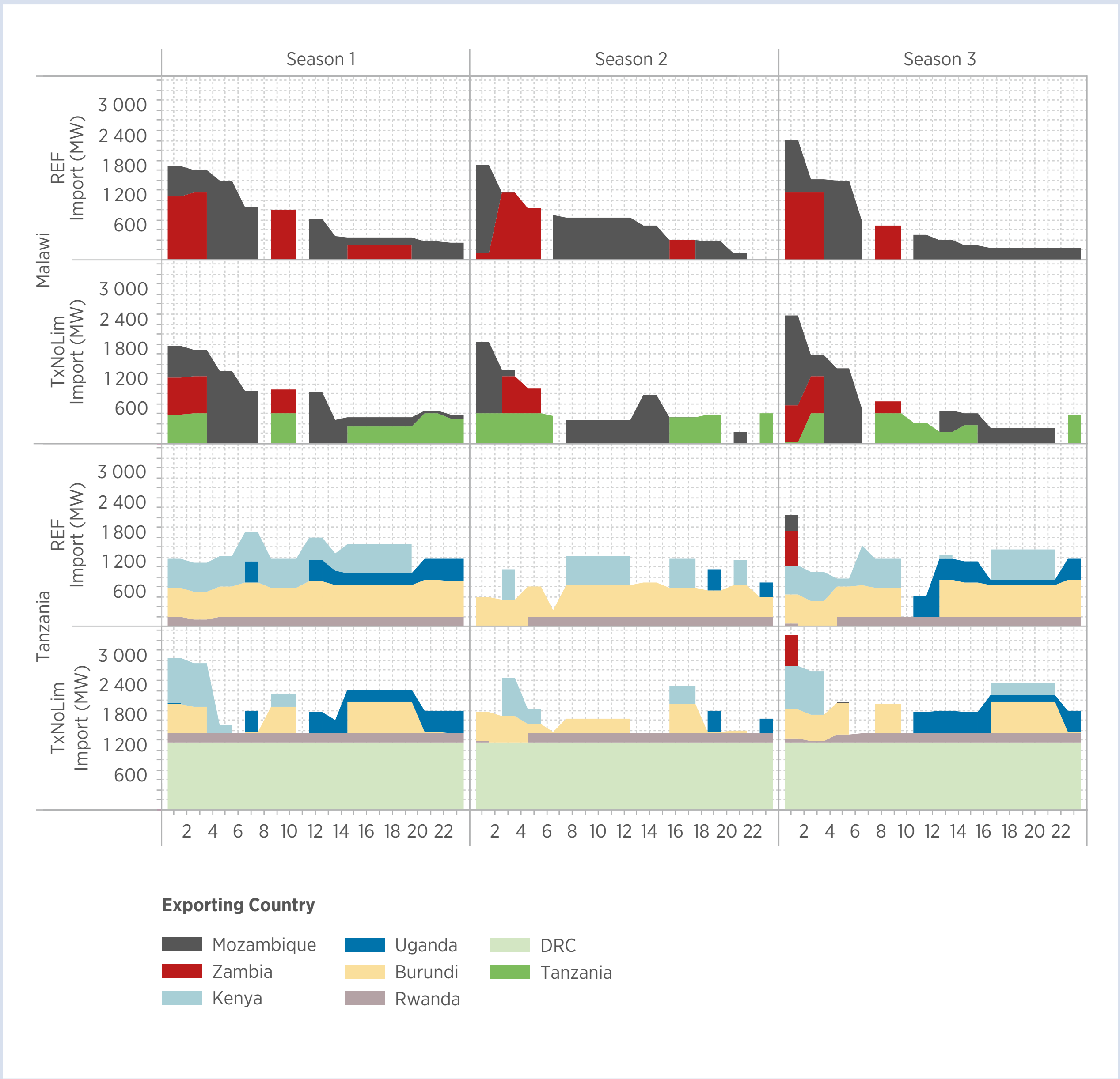
6.3.4 Mozambique–Tanzania and Mozambique–South Africa

Total 2040 flows on the interconnectors from Tanzania to Mozambique and from Mozambique to South Africa is higher in the VREHigh scenario (2 507 GWh and 13 631 GWh, respectively) as compared to the REF scenario (575 GWh and 13 631 GWh). As with the Tanzania–Malawi line, Tanzania is net importing, but it also is a transit country that forms a part of the route (DRC–Burundi–Tanzania) through which the DRC exports excess hydro production.

In the VREHigh scenario, there is also higher wind production in Tanzania. It will also increase the country's capability to export its excess electricity from wind production. Strengthening transmission capacity will especially facilitate the export of hydropower from the DRC, that will in turn meet demand needs in South Africa.

62 Lake Tanganyika forms the entire border between the DRC and Tanzania. This report uses the DRC–Tanzania capacity as a proxy for increased transitory capacity through other routes (e.g. through Rwanda, Burundi or Uganda).

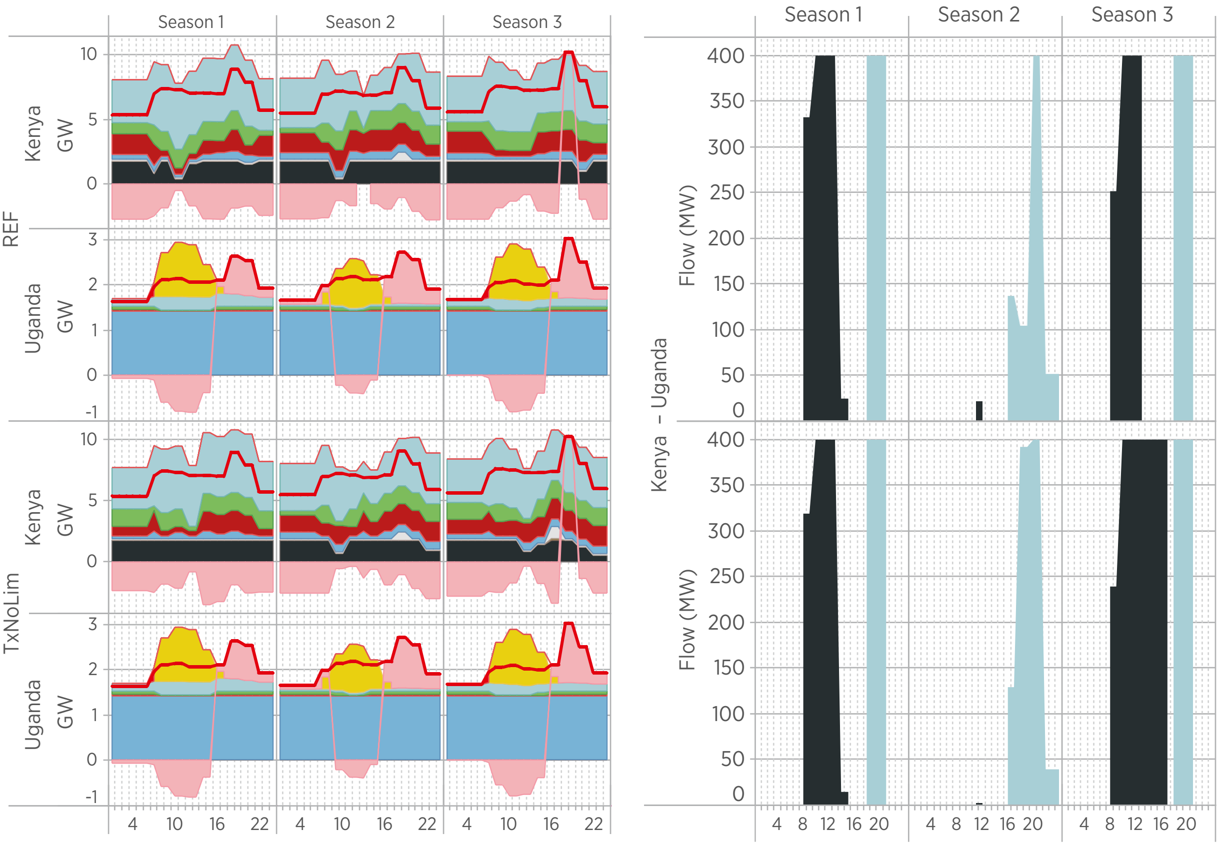
Figure 6-6: Modelled hourly imports by Malawi and Tanzania in 2040, REF and TxNoLim scenarios, in SAST (UTC+2:00)



6.3.5 Kenya–Uganda

The flow of electricity occurring along the Kenya–Uganda interconnector is another good example of how countries can take advantage of complementary generation profiles.[63] Figure 6-7 shows the modelled hourly production in Kenya and Uganda, and flows along the Kenya–Uganda interconnector. During the day, Uganda will be a net exporter because of high solar PV generation, and high hydropower production. It exports excess production from solar PV to Kenya, which will then be transmitted to Ethiopia. At night, when there is high power demand and no solar production in Uganda, Kenya can export its excess production from wind to Uganda. When a high level of VRE is deployed (VREHigh), the complementarity between solar and wind becomes more pronounced. Correspondingly, higher total flows are observed on the line (3 332 GWh in VREHigh; 1 097 GWh in REF). The connection can be strengthened to accommodate the increase in flows.

Figure 6-7: Modelled hourly production in Kenya and Uganda (left) with modelled flows on the Kenya–Uganda interconnector (right) in 2040, for the REF and TxNoLim scenarios, in SAST (UTC+2:00)



63 Another example of a complementary generation profile is discussed in Section 5 between the DRC and Rwanda.

CONCLUSIONS

The model-based analysis using SPLAT-ACEC was conducted to assist decision makers and analysts in the region to plan power systems in the medium and long term. Through the zoning analysis, high-potential locations are identified as candidate sites for VRE deployment. Results from the SPLAT-ACEC model under different scenarios reveal possible future developments in power generation and trade. In-depth analysis of the model results evaluates the contributions from the project zones identified.

The following conclusions can be made from analysing the main findings of the scenarios:

- **Unless generation capabilities are reviewed and re-imagined, the region is on track for the construction of some 107 GW of new coal-fired power based on existing master plans from 2020 to 2040, thereby tripling CO_2 emissions to 1 200 megatonnes per year.** The findings of this report pose a counter vision to a coal-dominated future, by showing that a high level of utility-scale solar PV and onshore wind penetration is possible with cost-driven investments in VRE sources. The existing stock of coal capacities (approximately 50 GW) can be reduced through retirement to 35 GW by 2040, as new solar PV and wind projects are preferred to the construction of new coal plants.

- **The regions are well endowed with wind and solar resources.** Not only are these resources of high quality, they are also regionally well-distributed. Of the 6 968 GW and 2 037 GW, respectively, of solar PV and wind zones identified, less than 1% is currently deployed. Among these, IRENA examined the economic potential of 335 zones (285 GW) in detail through the SPLAT-ACEC model.

- **Large amounts of VRE need to be deployed to ensure the cost-effectiveness of the power system in the region.** Excluding significant battery storage potential, 36% of power generation by solar PV and onshore wind by 2040 would be optimal, up from 2% in 2016. Capacities of wind and solar PV can reach 98 GW and 134 GW respectively, from a total of 7.6 GW today. With other dispatchable renewable energy technologies (especially hydropower), the total share of electricity generation by renewables increases to 63% by 2040 from 20% in 2016.

- **Compared to the master plans, IRENA's cost-optimal scenarios show that emissions from the power sector can peak mid-decade, reduce after 2025 and fall below 2015 levels by 2040.** If the VRE share in electricity generation was to increase to 50% by 2040 (e.g. through government intervention financially, or if lower costs than those projected materialise), CO_2 emissions would be driven down even further. If VRE deployment is limited to a 20% share of electricity generation by 2040 (e.g. by capping deployment to an upper bound, subsidising fossil fuels or disallowing market forces to influence technology choice), system cost will amount to USD 22 billion (approximately 1%) higher; CO_2 emissions from electricity generation are 15% higher in that scenario. The system cost does not include the cost of strengthening distribution networks or flexibility (i.e. no balancing market or ramping costs are considered).

- **Synergies between hydropower and wind help make the overall electricity system more flexible, both in domestic power systems and regionally.** For the former, this can be seen especially in Angola, Namibia, Ethiopia and Zambia, where solar PV produces in the day and hydropower produces at night.

- **Interconnector infrastructure expansions can facilitate power trade between regions with different types of renewable resources.** For example, hydropower generation profiles in the DRC and solar PV generation profiles in South Africa are shown to be complementary.

- **When hydropower production is reduced due to low hydrology or delayed projects, solar PV and wind power generation can be used to fill the supply gap. The supply mix can also be diversified by including 20 GW more biomass.**

- **The power system of the region can benefit from more cross-border trade as a balancing mechanism against high fluctuation of supplies from solar PV and wind.** Trade volumes increase by 4.5 times from 2020 to 2040, while 143 GW of new capacity additions would be expected. Of these, beyond the interconnector capacities which are already committed, there is still further potential for 15 GW of capacity by 2040. The number of country pairs with interconnectors can almost double from 18 to 35.

- **USD 2000 billion (in 2015 USD) in system costs (including investment cost for fuel and O&M costs) would be needed between 2020 and 2040, USD 960 billion of which relates to committed projects. The cumulative investment required for generation projects would be USD 560 billion for the above system.** Approximately USD 8 million would be needed for interconnector expansions. These costs are derived from a cost-minimisation model and would be subject to changes in assumptions. They serve to indicate the order of magnitude of investment requirements.

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APPENDICES

7

7.1 Methodology

7.1.1 Calculation of hourly capacity factors from meteorological data

Meteorological data for wind and solar farms are retrieved from Vortex. Vortex provides hourly wind speed at specific height and solar irradiance series at a 3 km resolution. The data are obtained for areas that are larger than zones and can comprise several zones. The calculated capacity factor profiles for each site are scaled to have the same average as the zone capacity factors from MapRE.

7.1.1.1 Wind

To compute the capacity factor for a wind turbine at an assumed height of 80 m, we utilised hourly wind speeds, temperatures and air pressures at 50 m to derive height- and air density-adjusted wind speeds. By applying the Wind Profile Power Law in Eq. 1, wind speeds at 80 m (v_{80}) are calculated, assuming neutral stability conditions. The Ideal Gas Law in Eq. 2 is then applied to calculate the adjusted density of air as a function of temperature and pressure. Finally, in Eq.3, the normalised wind speeds are calculated for a wind turbine so that they are consistent with wind speeds measured under the conditions for the International Standard IEC 61400-12 (IEC, 2015).

$$v_{80} = v_{50} \times \left(\frac{80}{50}\right)^{0.143} \qquad \text{Eq. 1}$$

$$\rho_{adj} = \frac{p}{R \times (T+273)} \qquad \text{Eq. 2}$$

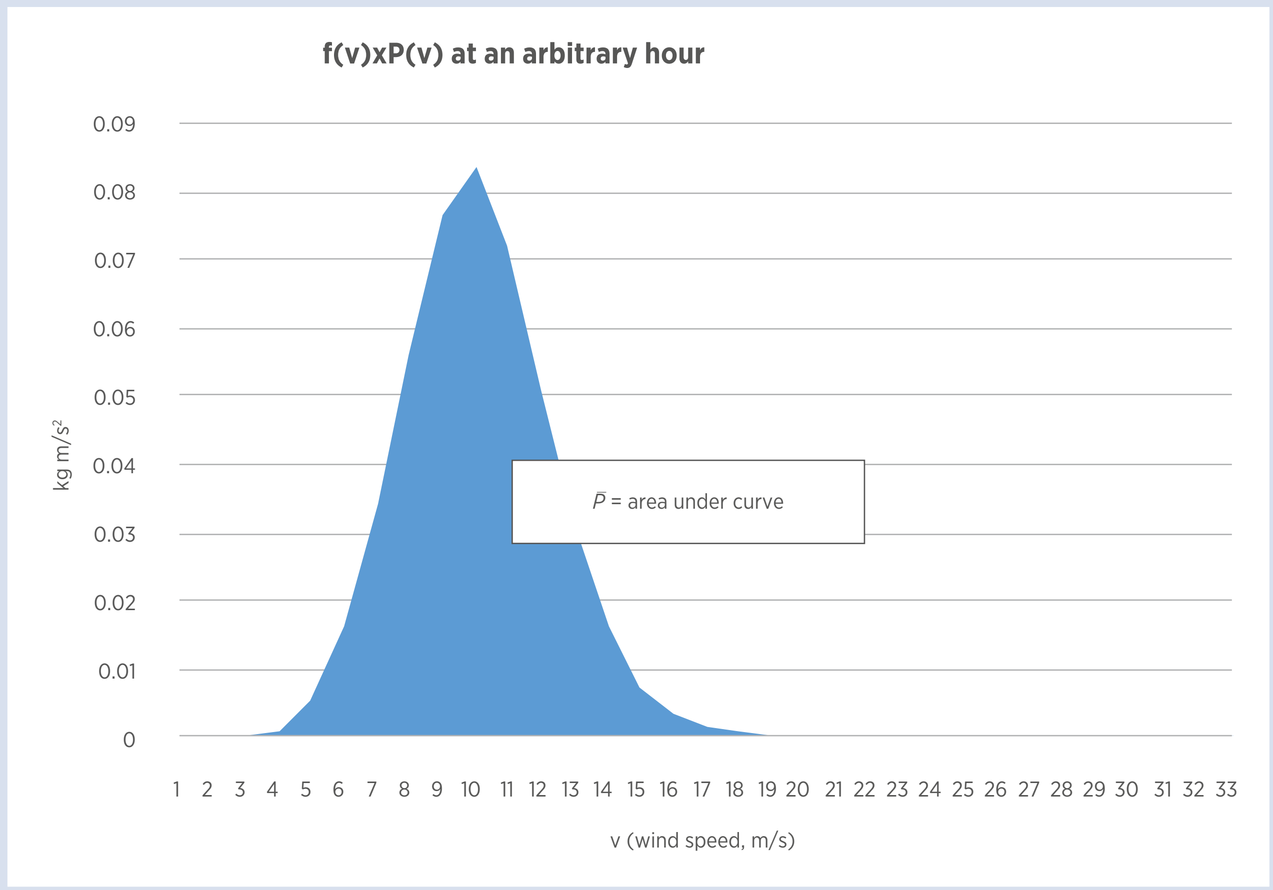
$$v_{80\_adj} = v_{80} \times \left(\frac{\rho_0}{\rho_{adj}}\right)^{1/3} \qquad \text{Eq. 3}$$

The average of hourly wind speeds is used to determine a suitable IEC class. Other factors such as wind gusts and turbulence intensity can also be used additionally to determine IEC classes, but they are not considered here for simplification.

IEC class	IEC Class 1	IEC Class 2	IEC Class 3
Average wind speed at 80 m (m/s)	>8.5	7.5–8.5	<7.5

For each hour, a Weibull probability distribution of wind speeds is generated based on the average wind speed of the hour and Weibull parameters (Gryning, et al., 2016). The power output at each wind speed bin is calculated based on the IEC class curve. After multiplying the power output with the probability at each bin of wind speed, the result is summed to obtain the mean power output ($\bar{P}$) of the hour.

$$\bar{P} = \sum f(v) \times P(v)$$



The capacity factor of the hour is finally calculated by including collection losses (η_a) and outages (η_o). Collection losses and outages are assumed to be 15% and 2%, respectively.

$$cf_{wind} = (1-\eta_a)(1-\eta_o) \times \bar{P}$$

For each zone, the hourly capacity factors of the site are then scaled to have the same yearly average reported by MapRE.

7.1.1.2 Solar

For calculating the capacity factor of solar PV, we adopted a model that uses the module temperature and in-plane irradiance to calculate power output (Huld et al., 2010).

$$P = P_{STC} \cdot \frac{G}{G_{STC}} \cdot \eta_{rel}(G', T')$$

Where STC refers to standard test conditions, $G' = G/G_{STC}$ with $G_{STC} = 1000\,\mathrm{W/m^2}$, $T' = T - T_{STC}$ with $T_{STC} = 25\,°\mathrm{C}$. The relative efficiency is given by:

$$\eta_{rel} = 1 + k_1 \ln G' + k_2[\ln G']^2 + T'(k_3 + k_4 \ln G' + k_5[\ln G']^2) + k_6\, T'^2$$

The temperature of the module can be estimated using the ambient temperature and irradiation through:

$$T_{mod} = T_{amb} + c_T G$$

The model assumes a c-Si module with a temperature coefficient of 0.035%/K and is free-standing rack-mounted in the absence of wind, verified using data from Ispra, Italy (Huld et al., 2010).

For each zone, the hourly capacity factors of the site are then scaled to have the same yearly average reported by MapRE.

7.2 Assumptions

7.2.1 Demand assumptions

The country-specific demand projections used in the model are derived from the EAPP and SAPP master plans (EAPP, 2014; SAPP, 2017).

GWh	Angola	Botswana	Burundi	DRC	Djibouti	Egypt	Eswatini	Ethiopia	Kenya	Lesotho	Malawi	Mozambique	Namibia	Rwanda	South Africa	South Sudan	Sudan	Tanzania	Uganda	Zambia	Zimbabwe
2015	9 105	3 974	249	10 499	635	201 461	1 141	14 688	13 310	645	1 756	12 686	3 871	883	215 693	747	16 662	6 320	3 500	14 000	9 557
2016	9 883	4 260	340	10 688	728	216 383	1 202	18 816	13 988	680	2 204	13 304	4 117	1 094	223 362	991	18 232	7 742	3 727	14 927	9 813
2017	10 661	4 547	431	10 877	820	231 305	1 262	22 944	14 665	715	2 651	13 922	4 363	1 305	231 033	1 236	19 802	9 164	3 955	15 855	10 069
2018	11 438	4 833	522	11 067	913	246 227	1 323	27 072	15 343	749	3 099	14 540	4 608	1 516	238 702	1 480	21 372	10 586	4 182	16 782	10 325
2019	12 216	5 120	613	11 256	1 006	261 150	1 383	31 200	16 020	784	3 546	15 158	4 854	1 727	246 372	1 724	22 942	12 008	4 410	17 710	10 581
2020	12 994	5 406	704	11 445	1 099	276 071	1 444	35 328	16 698	819	3 994	15 775	5 100	1 938	254 042	1 968	24 512	13 430	4 637	18 638	10 837
2021	14 597	5 644	762	12 159	1 188	291 874	1 505	41 623	18 954	873	4 657	16 258	5 305	2 065	261 860	2 199	26 005	15 687	5 345	19 472	11 390
2022	16 201	5 883	821	12 872	1 278	307 676	1 566	47 917	21 210	927	5 321	16 741	5 509	2 192	269 677	2 430	27 498	17 944	6 053	20 307	11 944
2023	17 805	6 121	880	13 586	1 368	323 478	1 627	54 211	23 467	980	5 984	17 223	5 714	2 319	277 495	2 660	28 992	20 201	6 761	21 142	12 497
2024	19 408	6 360	939	14 300	1 458	339 280	1 688	60 505	25 723	1 034	6 647	17 706	5 919	2 446	285 312	2 891	30 485	22 458	7 469	21 977	13 050
2025	21 011	6 598	998	15 014	1 548	355 082	1 749	66 800	27 979	1 088	7 311	18 188	6 124	2 573	293 131	3 121	31 979	24 715	8 177	22 811	13 603
2026	22 615	6 836	1 057	15 727	1 638	370 884	1 810	73 094	30 235	1 142	7 974	18 671	6 328	2 700	300 948	3 352	33 472	26 972	8 885	23 646	14 157
2027	24 219	7 075	1 116	16 441	1 728	386 687	1 871	79 388	32 491	1 196	8 637	19 154	6 533	2 827	308 765	3 582	34 966	29 229	9 593	24 481	14 710
2028	25 822	7 313	1 175	17 155	1 818	402 489	1 932	85 682	34 748	1 249	9 300	19 636	6 738	2 954	316 584	3 813	36 459	31 486	10 301	25 316	15 263
2029	27 425	7 552	1 234	17 868	1 907	418 292	1 993	91 976	37 004	1 303	9 964	20 119	6 942	3 081	324 401	4 043	37 953	33 743	11 010	26 151	15 817
2030	29 029	7 790	1 293	18 582	1 997	434 094	2 054	98 271	39 260	1 357	10 627	20 601	7 147	3 208	332 219	4 274	39 446	36 000	11 718	26 985	16 370
2031	31 967	7 949	1 363	19 875	2 072	449 896	2 076	104 565	41 371	1 431	12 175	21 130	7 441	3 380	337 276	4 504	41 052	41 188	12 348	27 820	16 960
2032	34 906	8 107	1 432	21 168	2 147	465 698	2 098	110 860	43 482	1 505	13 723	21 658	7 735	3 553	342 332	4 733	42 657	46 376	12 978	28 655	17 550
2033	37 844	8 266	1 502	22 461	2 222	481 500	2 121	117 154	45 593	1 579	15 270	22 187	8 028	3 725	347 388	4 963	44 263	51 564	13 608	29 490	18 140
2034	40 783	8 425	1 571	23 754	2 297	497 303	2 143	123 448	47 704	1 653	16 818	22 715	8 322	3 898	352 445	5 193	45 868	56 752	14 238	30 324	18 730
2035	43 721	8 583	1 641	25 047	2 372	513 105	2 165	129 743	49 815	1 727	18 366	23 244	8 616	4 070	357 501	5 423	47 474	61 940	14 868	31 159	19 320
2036	46 659	8 742	1 710	26 339	2 447	528 907	2 187	136 037	51 926	1 800	19 914	23 772	8 910	4 243	362 557	5 652	49 080	67 128	15 498	31 994	19 910
2037	49 598	8 901	1 780	27 632	2 522	544 709	2 209	142 331	54 037	1 874	21 462	24 301	9 204	4 415	367 613	5 882	50 685	72 316	16 128	32 829	20 500
2038	52 536	9 060	1 849	28 925	2 596	560 511	2 232	148 625	56 148	1 948	23 009	24 830	9 498	4 588	372 670	6 112	52 291	77 504	16 758	33 663	21 090
2039	55 475	9 218	1 919	30 218	2 671	576 313	2 254	154 919	58 259	2 022	24 557	25 358	9 791	4 760	377 726	6 342	53 897	82 692	17 388	34 498	21 680
2040	58 413	9 377	1 989	31 511	2 746	592 116	2 276	161 213	60 370	2 096	26 105	25 887	10 085	4 933	382 783	6 571	55 502	87 880	18 018	35 333	22 270

7.2.2 Technology assumptions

Technology	Overnight cost						Fixed O&M (% of overnight cost)	Construction time	Availability	Efficiency	Life in years
	2015	2020	2025	2030	2035	2040					
PV system (utility)	2 165	1 378	984	886	800	723	1.3%	1	100%	100%	24
Solar thermal with storage (all countries)	8 645	5 797	4 670	3 763	3 711	3 660	1%	2	100%	100%	30
Solar thermal with storage (Egypt)	5 187	4 394	3 722	3 153	3 153	3 153					
Wind (all countries)	1 985	1 489	1 191	1 087	933	933	4%	2	100%	100%	25
Wind (Egypt)	1 489	1 191	1 087	933	933	933					
Biomass	2 500						3%	4	67%	35%	30
Coal	3 739						3%	4	85%	39%	35
Nuclear	6 137						3%	6	85%	33%	50
Diesel engine	1 086						3%	1	80%	35%	25
Diesel open cycle	795						3%	2	85%	35%	25
Gas combined cycle	1 014						3%	3	85%	58%	30
Gas open cycle	795						3%	2	85%	35%	25
Gas engine	1 086						3%	2	85%	45%	25
Geothermal	4 000						3%	4	60%	100%	25
HFO engine	1 086						3%	2	80%	35%	25
HFO steam turbine	1 086						3%	2	80%	35%	25
Hydro small	3 000						3%	2	50%	100%	50
Hydro run-of-river	2 500						3%	2	50%	100%	50
Hydro with dam	3 000						3%	5	50%	100%	50
Backstop	9 999						3%	1	100%	100%	2

7.3 Summary of results

Variable	RELow		REF		REHigh		HYDel		HYDry		TxEx2030	
	2030	2040	2030	2040	2030	2040	2030	2040	2030	2040	2030	2040
CO_2 Emissions (ktons)	470 256	426 054	454 503	357 174	426 405	319 618	458 490	357 718	460 467	370 538	454 506	353 410
RE Share	36.5%	50.2%	40.2%	62.7%	47.0%	70.7%	38.9%	60.5%	39.3%	62.6%	40.2%	63.2%
VRE Share	10.0%	20.0%	16.7%	36.0%	25.0%	50.0%	20.5%	36.9%	20.2%	35.7%	16.7%	36.0%
Sytem Costs (M$)												
Annualised Investment Costs	614 753	1 313 848	617 672	1 375 715	625 633	1 430 875	638 728	1 415 036	632 402	1 390 856	617 669	1 376 365
O&M Costs	151 195	306 069	151 596	316 139	152 991	332 521	152 984	320 743	145 674	308 731	151 596	315 937
Fuel Costs	332 929	725 699	327 708	630 889	318 167	570 815	340 948	658 501	336 439	642 217	327 711	629 094
Grand Total	**1 098 876**	**2 345 615**	**1 096 976**	**2 322 743**	**1 096 792**	**2 334 210**	**1 132 660**	**2 394 280**	**1 114 515**	**2 341 804**	**1 096 977**	**2 321 397**
Cumulative New Capacity since 2018 (MW)												
Biomass	5 278	19 373	1 945	16 922	1 919	9 261	2 707	20 293	3 774	17 089	1 945	16 918
Geothermal	3 607	3 607	3 462	3 462	2 883	2 883	5 100	5 100	6 835	6 835	3 462	3 462
Large Hydropower	33 742	50 551	31 257	43 744	28 871	39 355	26 253	39 982	13 234	39 255	31 268	45 335
Solar PV - Utility	4 981	69 490	24 291	133 425	54 745	128 546	42 146	135 492	38 377	130 634	24 259	134 110
Solar Thermal	2 400	2 400	2 400	2 400	2 400	2 400	2 400	2 400	2 400	2 400	2 400	2 400
Wind	24 457	49 716	34 915	97 492	45 535	213 969	36 454	101 930	38 183	97 272	34 916	96 831
Grand Total	**74 465**	**195 137**	**98 269**	**297 445**	**136 353**	**396 414**	**115 061**	**305 197**	**102 804**	**293 485**	**98 249**	**299 056**

7.4 Capacity and generation results for modelled countries in the Reference scenario

Country	Technology Type	Capacity (MW) 2030	Capacity (MW) 2040	Generation (GWh) 2030	Generation (GWh) 2040
Angola	Biomass	-	1 292	-	7 584
	Diesel	842	842	369	369
	Large Hydropower	5 987	6 437	20 944	23 644
	Natural Gas	870	870	5 638	1 226
	Oil Products	20	20	9	9
	Solar PV- Utility	1 197	7 048	2 666	13 627
Botswana	Biomass	-	20	-	116
	Coal	778	778	5 794	5 794
	Solar PV- Utility	-	1 103	-	2 113
Burundi	Large Hydropower	182	182	930	930
	Solar PV- Utility	20	208	42	436
DRC	Diesel	190	190	83	83
	Large Hydropower	3 919	12 347	16 618	75 552
	Natural Gas	5	5	2	2
	Small Hydropower	34	7	121	26
	Solar PV- Utility	600	3 223	1 282	6 612
Djibouti	Biomass	3	3	16	16
	Geothermal	90	90	473	473
	Natural Gas	158	294	504	403
	Oil Products	110	110	48	48
	Solar PV- Utility	35	35	63	63
	Wind	286	425	928	1 353
Egypt	Biomass	15	15	88	88
	Coal	7 600	7 600	56 595	56 595
	Diesel	344	23	151	10
	Large Hydropower	2 800	2 800	13 642	13 642
	Natural Gas	56 181	85 914	265 568	264 369
	Nuclear	2 400	2 400	17 872	17 872
	Nuclear Fuel	-	-	194 969	194 969
	Oil Products	2 778	2 078	1 217	910
	Pumped Storage	2 400	2 400	590	590
	Pumping	2 400	2 400	590	590
	Small Hydropower	31	31	-	-
	Solar PV- Utility	750	49 079	1 432	95 436
	Solar Thermal	2 240	2 100	5 954	5 582
	Wind	21 739	41 467	74 301	129 554

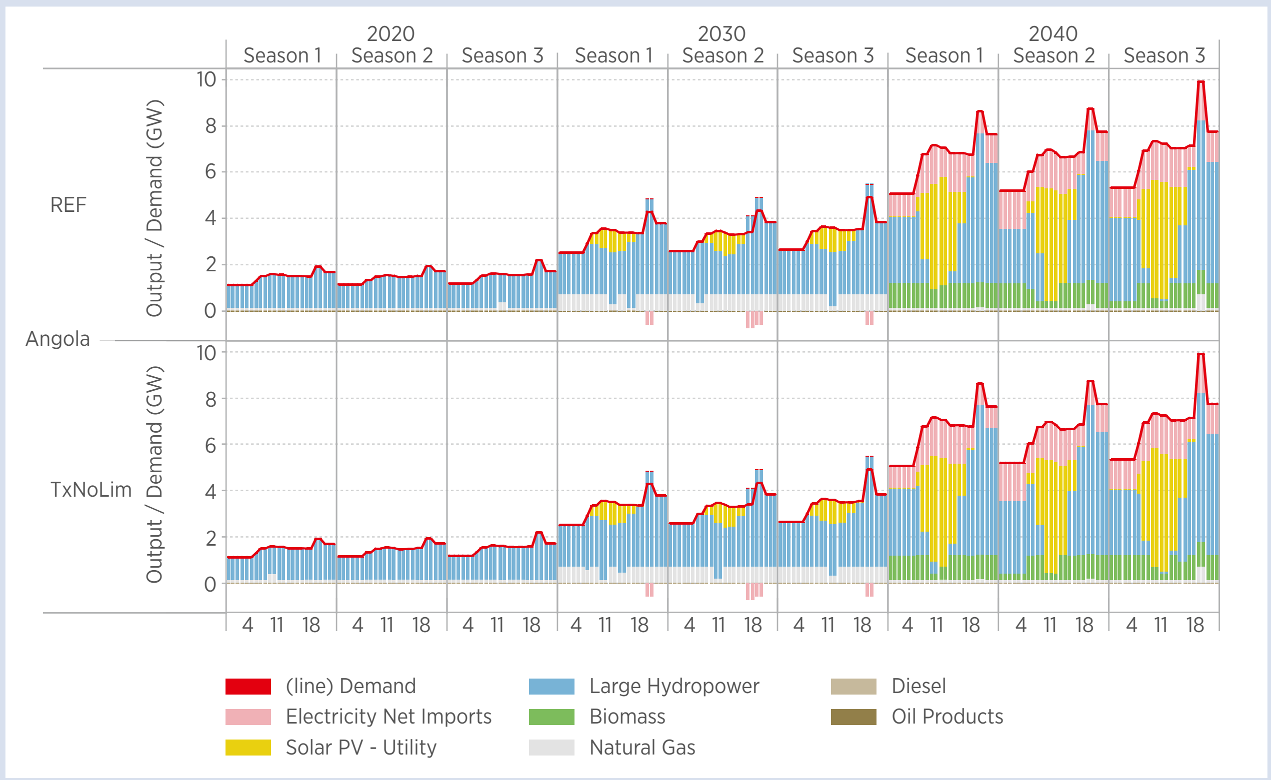
Country	Technology Type	Capacity (MW) 2030	Capacity (MW) 2040	Generation (GWh) 2030	Generation (GWh) 2040
Eswatini	Biomass	-	95	-	559
	Large Hydropower	72	67	233	218
	Solar PV- Utility	-	230	-	403
	Wind	-	121	-	328
Ethiopia	Biomass	614	3 737	3 604	21 929
	Diesel	87	39	38	17
	Geothermal	1 845	1 840	9 696	9 669
	Large Hydropower	16 946	19 147	59 497	68 561
	Natural Gas	-	5 802	-	5 402
	Solar PV- Utility	4 329	18 131	10 041	37 147
	Wind	1 296	2 098	4 013	6 491
Kenya	Biomass	44	1 793	258	10 520
	Coal	1 920	1 920	14 298	14 298
	Diesel	120	-	53	-
	Geothermal	2 317	2 181	12 176	11 461
	Large Hydropower	783	783	3 928	3 928
	Natural Gas	1 058	1 413	1 077	1 365
	Oil Products	215	163	94	71
	Small Hydropower	11	11	-	-
	Wind	4 654	8 889	20 071	36 361
Lesotho	Biomass	-	52	-	306
	Large Hydropower	80	80	332	332
	Pumped Storage	1 200	1 200	98	441
	Pumping	1 200	1 200	98	441
	Solar PV- Utility	95	228	197	450
	Wind	-	68	-	168
Malawi	Biomass	428	442	2 514	2 595
	Coal	258	258	1 921	1 921
	Diesel	75	75	33	33
	Large Hydropower	905	905	4 658	4 658
	Natural Gas	294	294	230	129
	Oil Products	38	38	17	17
	Small Hydropower	9	9	17	17
	Solar PV- Utility	97	1 731	203	3 407
	Wind	177	2 466	566	6 183

Country	Technology Type	Capacity (MW)		Generation (GWh)	
		2030	2040	2030	2040
Mozambique	Biomass	-	2 181	-	12 800
	Coal	1 500	1 500	11 170	11 170
	Diesel	136	40	60	60
	Large Hydropower	3 718	3 768	25 115	25 444
	Natural Gas	908	612	4 479	1 570
	Solar PV- Utility	60	2 862	118	5 693
Namibia	Biomass	-	21	-	120
	Coal	120	120	894	894
	Diesel	23	23	10	10
	Large Hydropower	647	647	2 999	2 999
	Oil Products	26	26	17	11
	Solar PV- Utility	676	976	1 149	1 908
	Wind	77	921	31	2 391
Rwanda	Coal	145	130	1 080	968
	Diesel	67	50	29	22
	Large Hydropower	121	121	699	699
	Natural Gas	202	200	88	162
	Oil Products	20	-	9	-
	Solar PV- Utility	28	543	58	1 049
South Africa	Biomass	1 180	1 268	6 926	7 442
	Coal	31 300	17 640	214 812	125 071
	Diesel	2 906	3 594	1 367	1 574
	Large Hydropower	644	42	283	18
	Natural Gas	5 917	25 024	7 859	27 740
	Nuclear	1 800	1 800	13 404	13 404
	Nuclear Fuel	-	-	146 227	146 227
	Pumped Storage	2 912	2 912	716	4 981
	Pumping	2 912	2 912	716	4 981
	Small Hydropower	19	19	-	-
	Solar PV- Utility	15 472	31 767	33 510	65 726
	Solar Thermal	700	700	2 182	2 182
	Wind	9 001	26 175	28 647	79 502
South Sudan	Biomass	-	33	-	195
	Diesel	346	346	152	152
	Large Hydropower	1 102	1 342	4 918	5 983
	Solar PV- Utility	-	544	-	868

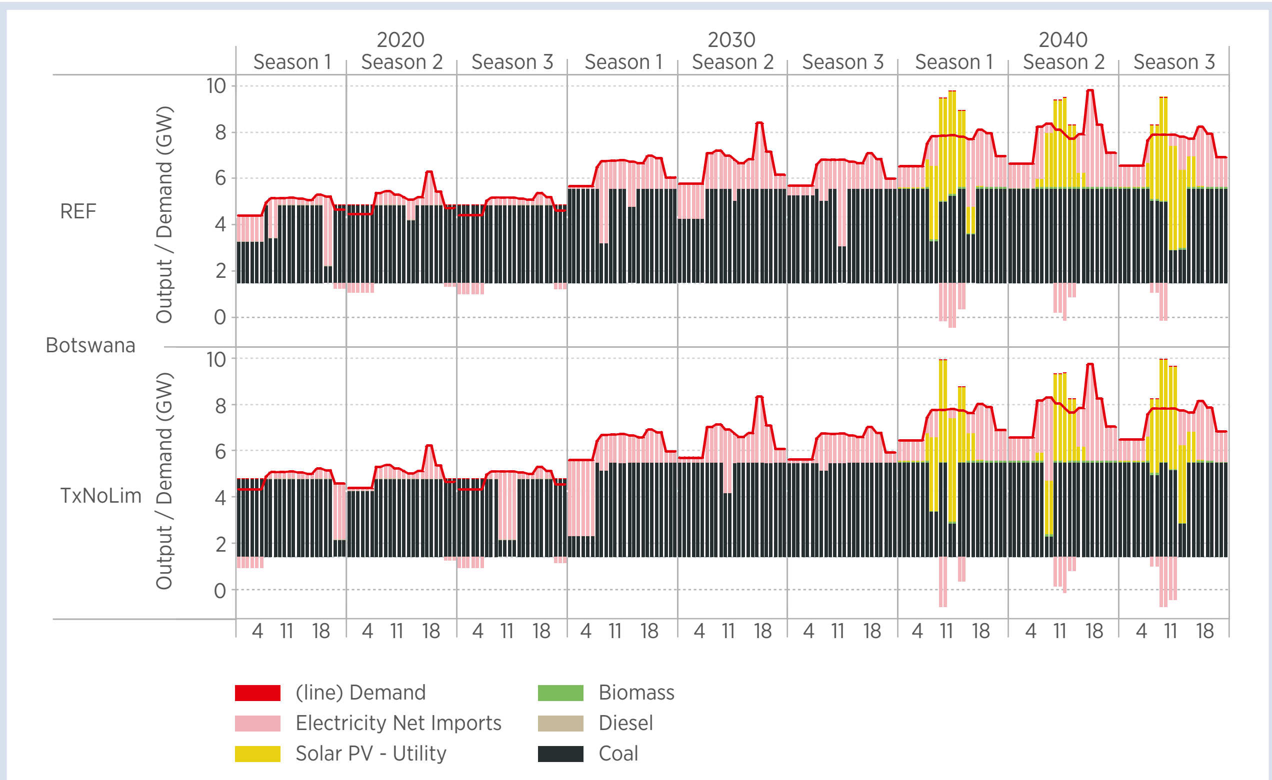
Country	Technology Type	Capacity (MW) 2030	Capacity (MW) 2040	Generation (GWh) 2030	Generation (GWh) 2040
Sudan	Biomass	-	2 066	-	12 122
	Coal	634	534	4 721	3 977
	Large Hydropower	3 615	3 615	15 811	15 811
	Natural Gas	900	900	6 702	1 692
	Oil Products	1 179	1 069	516	468
	Small Hydropower	10	10	-	-
	Solar PV- Utility	1 079	2 239	2 427	4 981
	Wind	1 555	8 210	5 530	24 265
Tanzania	Biomass	17	2 138	100	12 549
	Coal	2 200	2 200	16 383	16 383
	Large Hydropower	3 012	3 649	9 739	12 640
	Natural Gas	2 270	3 846	12 001	6 297
	Oil Products	60	-	26	-
	Small Hydropower	24	24	-	-
	Solar PV- Utility	1 372	7 428	3 124	16 761
	Wind	-	3 980	-	12 630
Uganda	Biomass	128	86	751	505
	Coal	33	-	58	-
	Geothermal	50	50	263	263
	Large Hydropower	2 226	2 226	12 374	12 374
	Oil Products	150	100	66	44
	Solar PV- Utility	20	1 439	43	3 153
	Wind	-	458	-	1 395
Zambia	Biomass	-	1 413	-	8 291
	Coal	900	900	6 702	6 702
	Large Hydropower	4 556	4 556	21 829	21 829
	Small Hydropower	40	40	-	-
	Solar PV- Utility	-	3 262	-	6 892
	Wind	-	1 337	-	3 776
Zimbabwe	Biomass	-	328	-	1 925
	Coal	1 437	1 437	10 701	10 701
	Large Hydropower	2 280	2 280	9 734	9 734
	Solar PV- Utility	439	1 745	958	3 753
	Wind	-	1 476	-	4 406

7.5 Dispatch patterns of individual countries

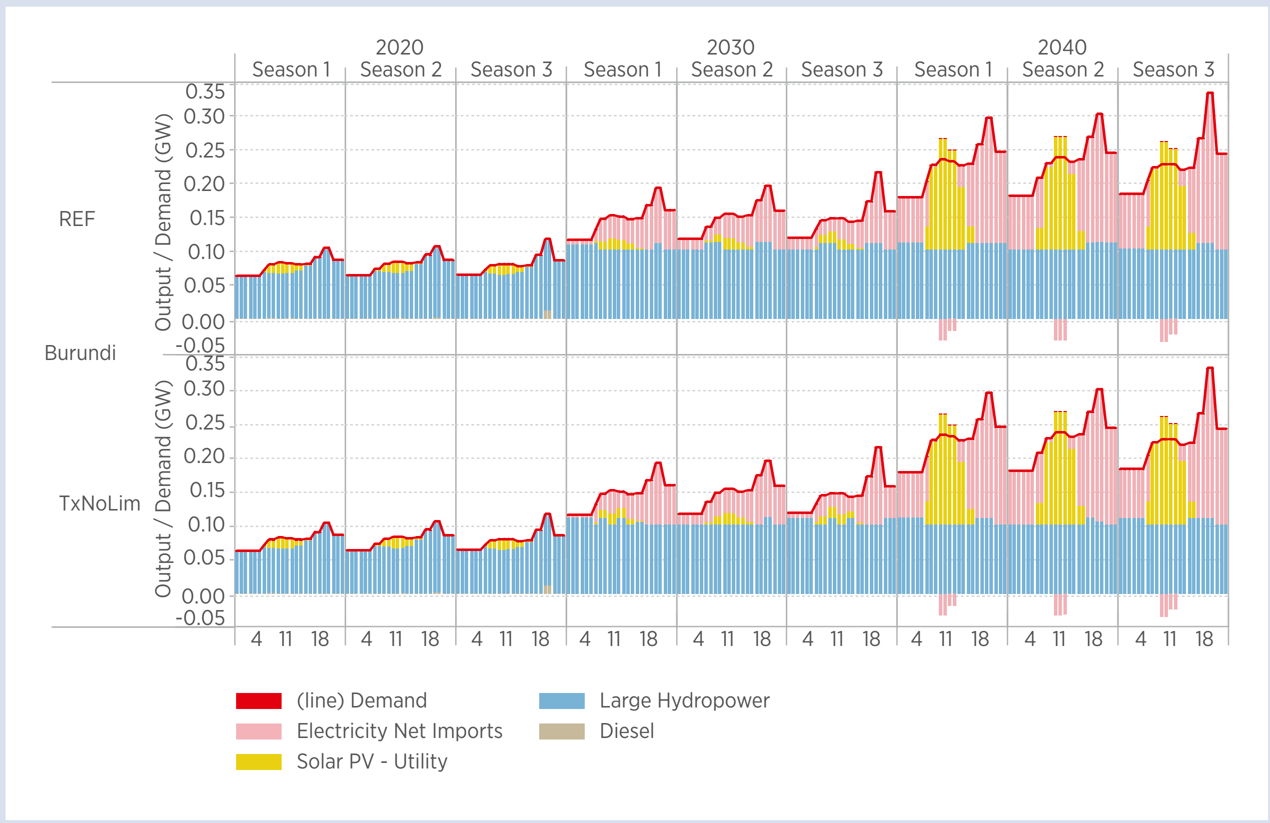
Angola



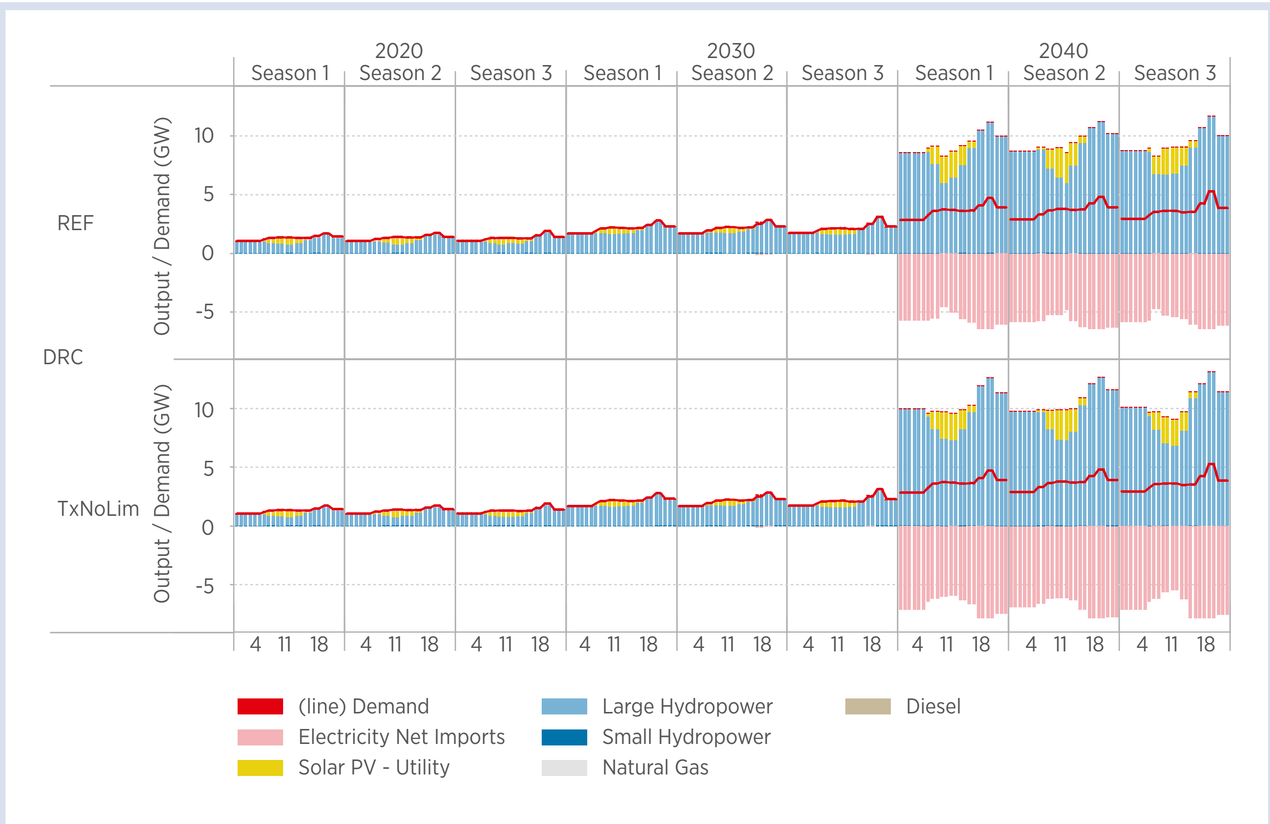
Botswana



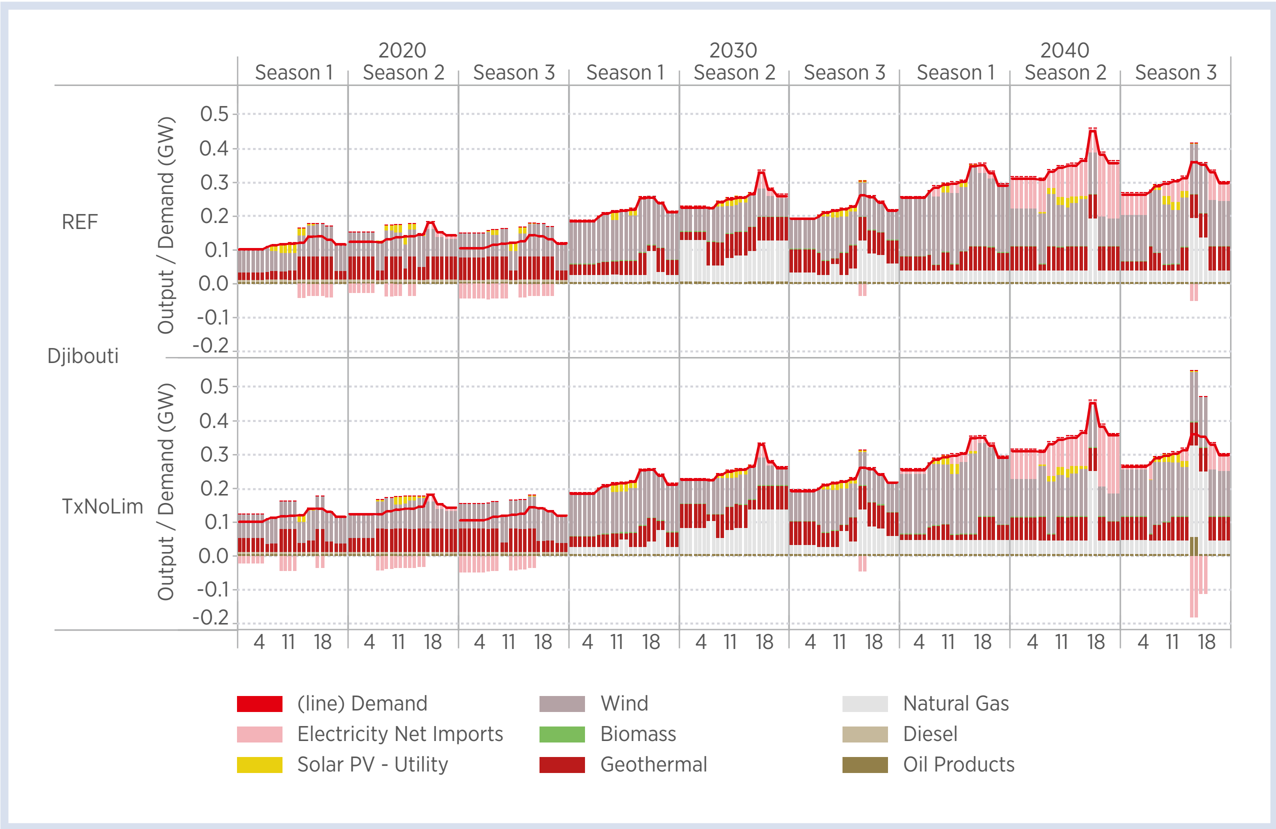
Burundi



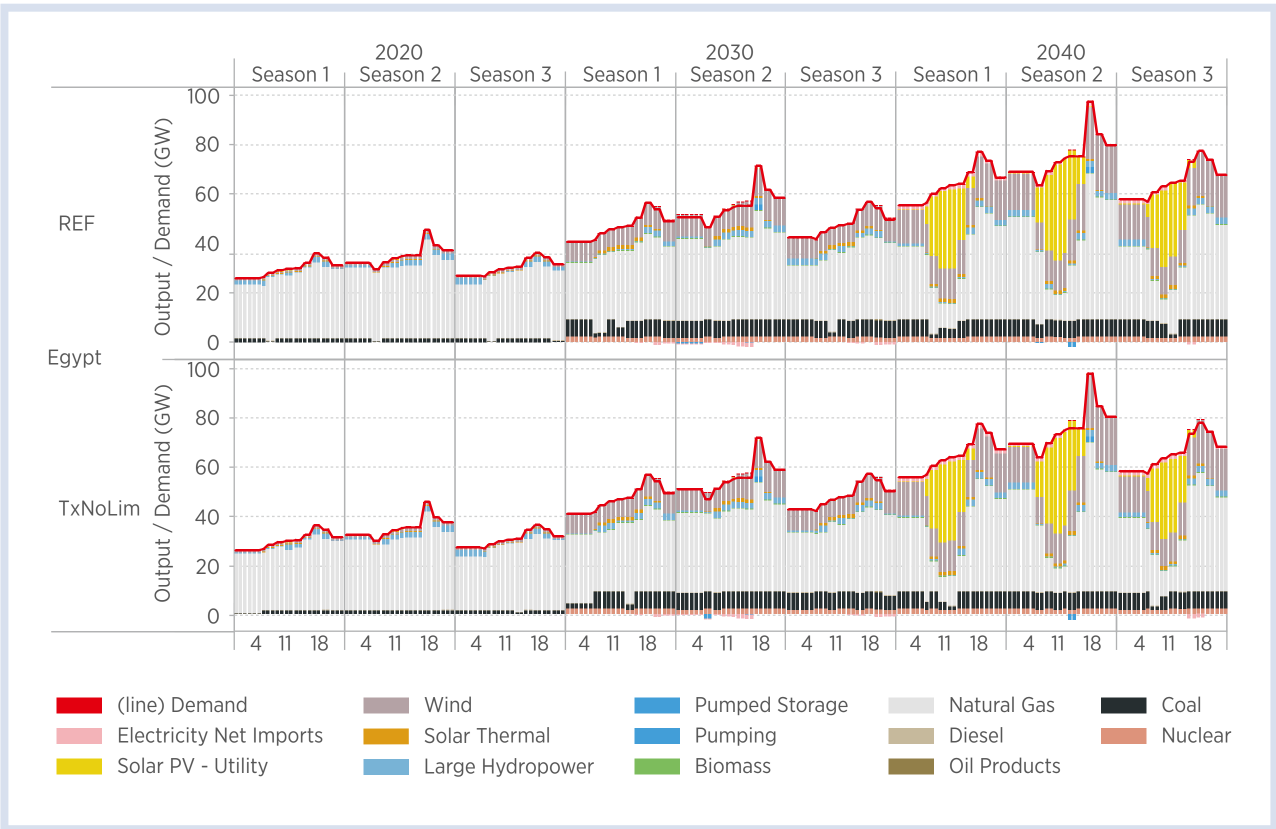
Democratic Republic of the Congo



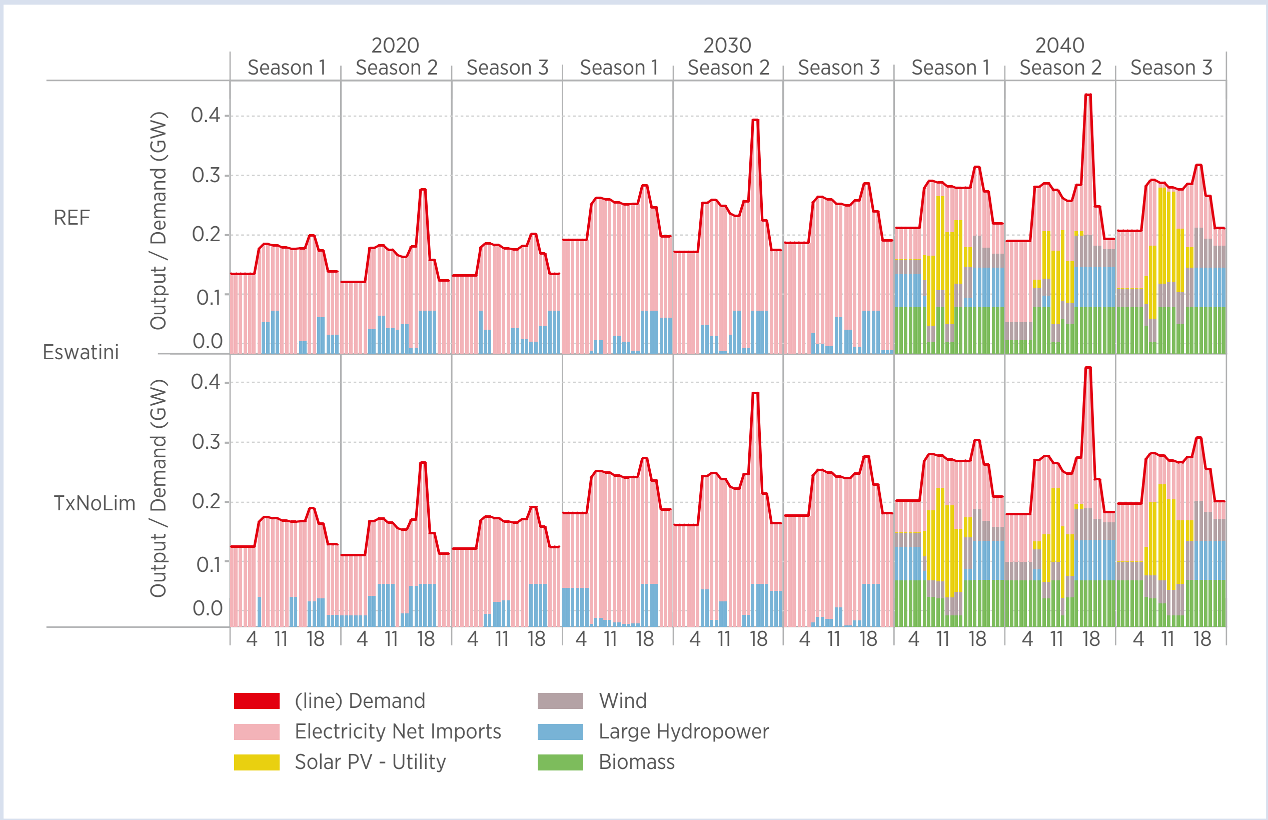
Djibouti



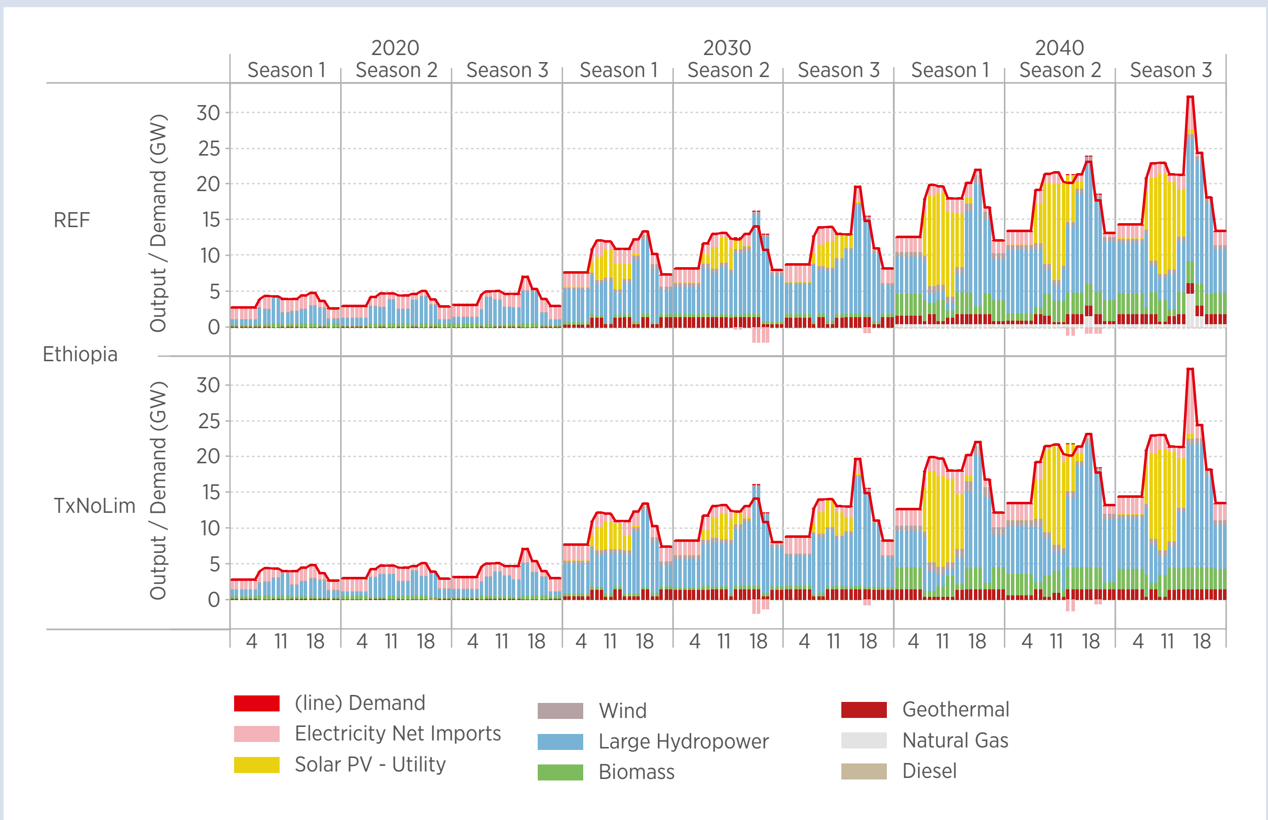
Egypt



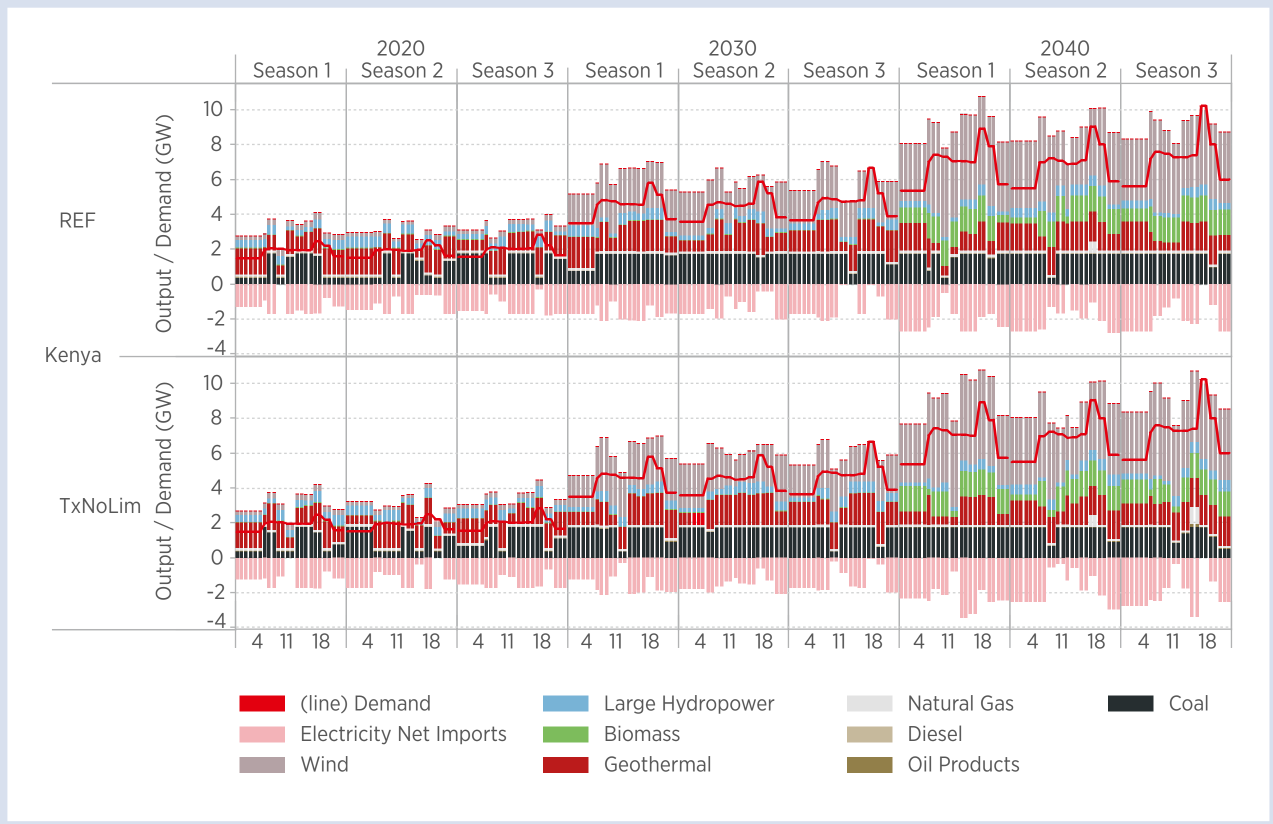
Eswatini



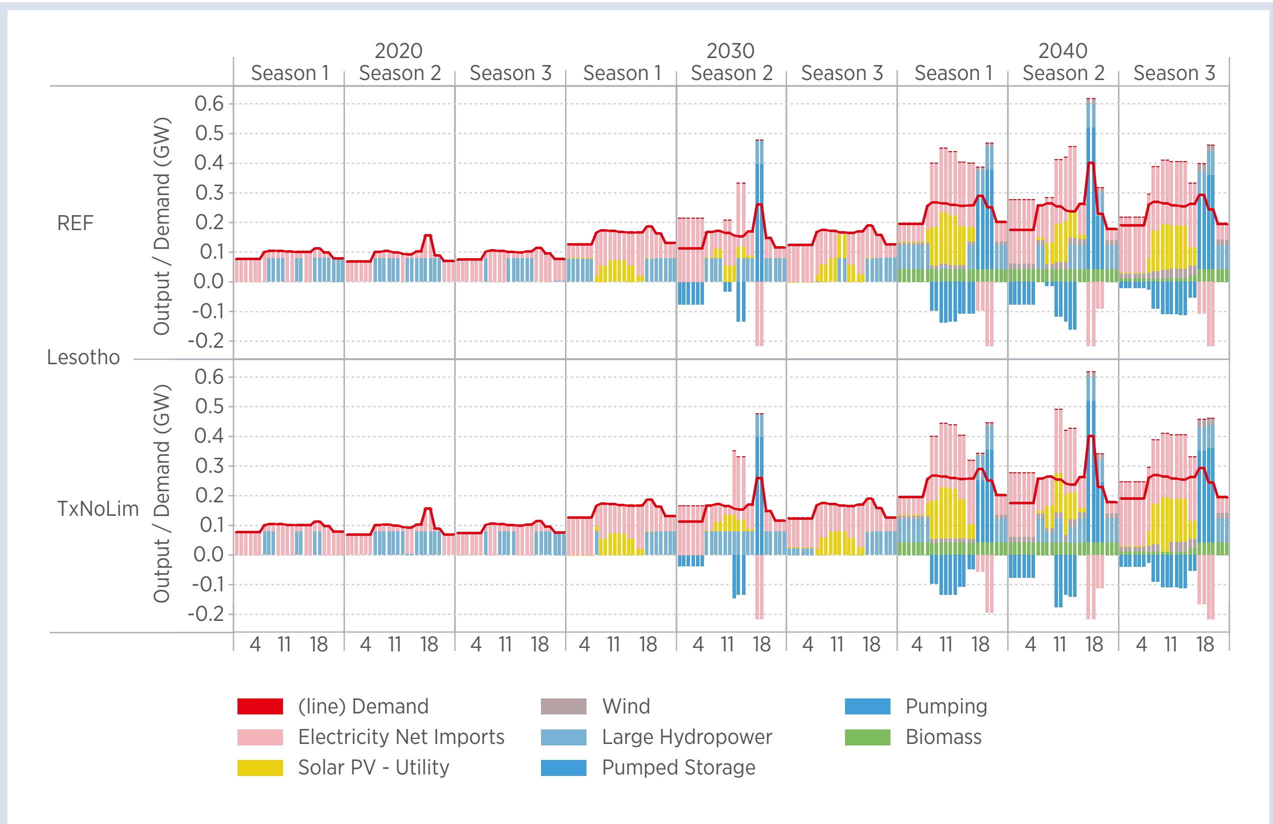
Ethiopia



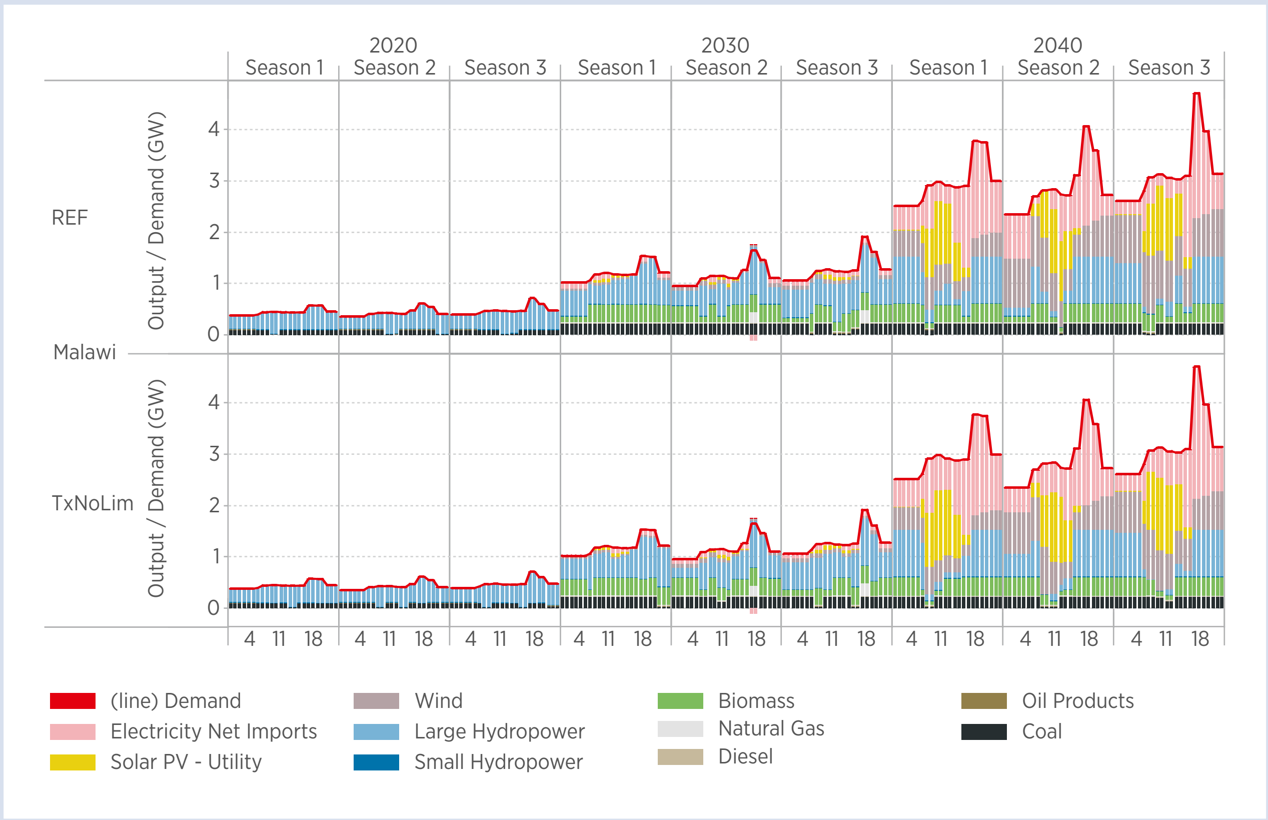
Kenya



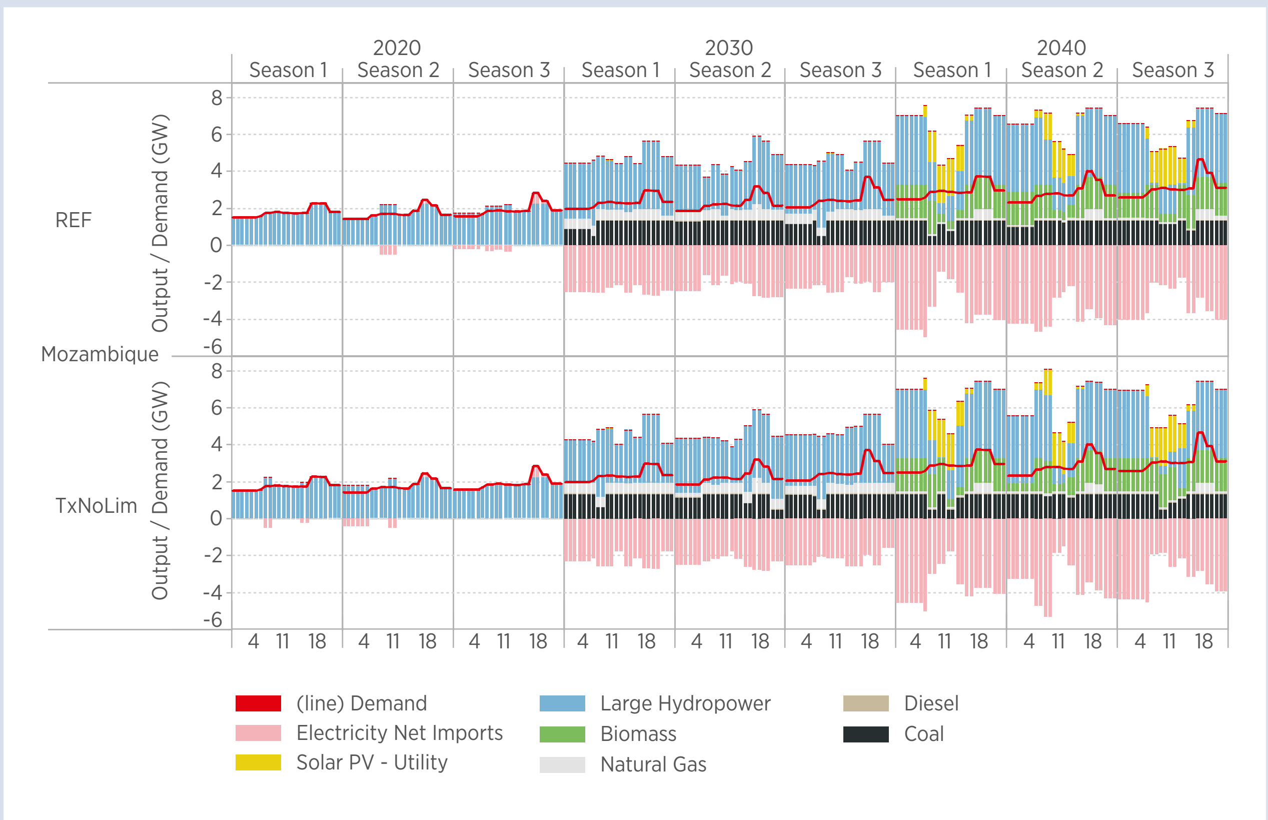
Lesotho



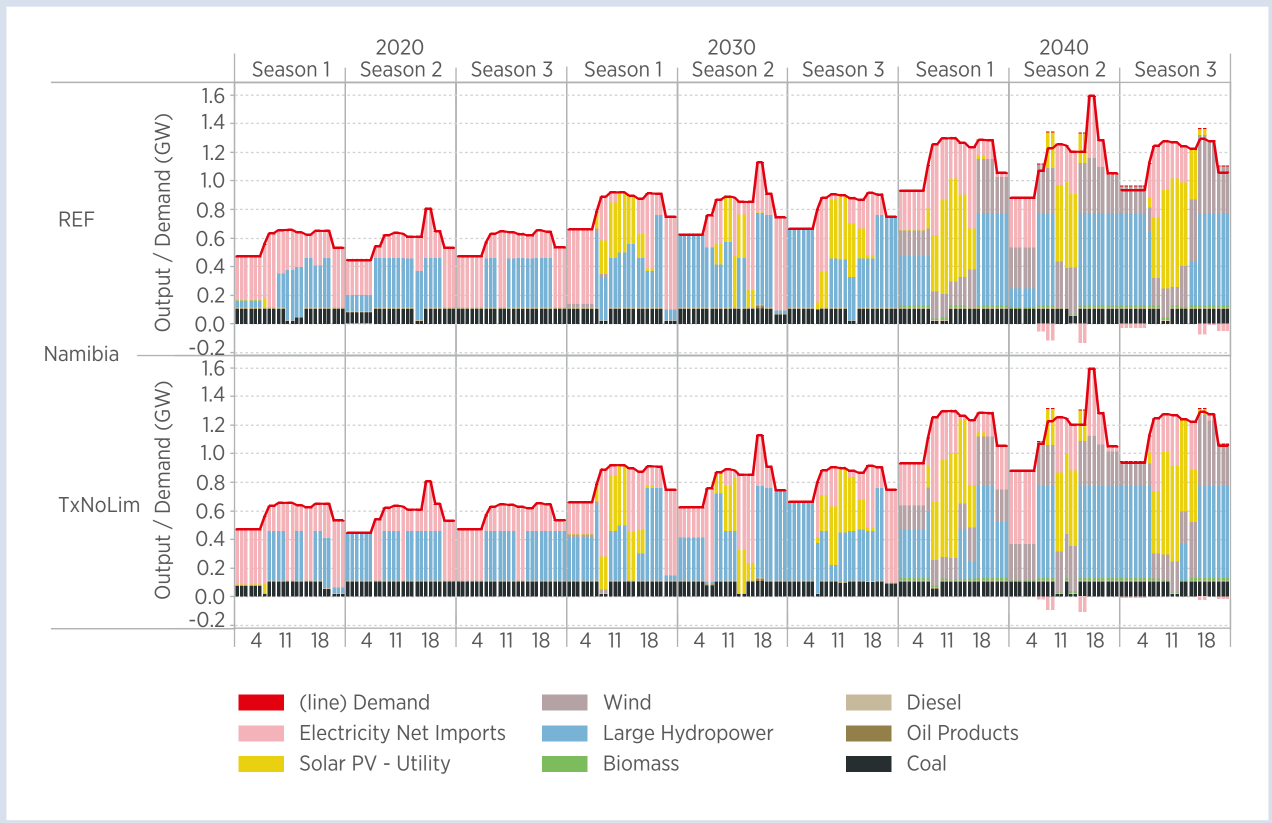
Malawi



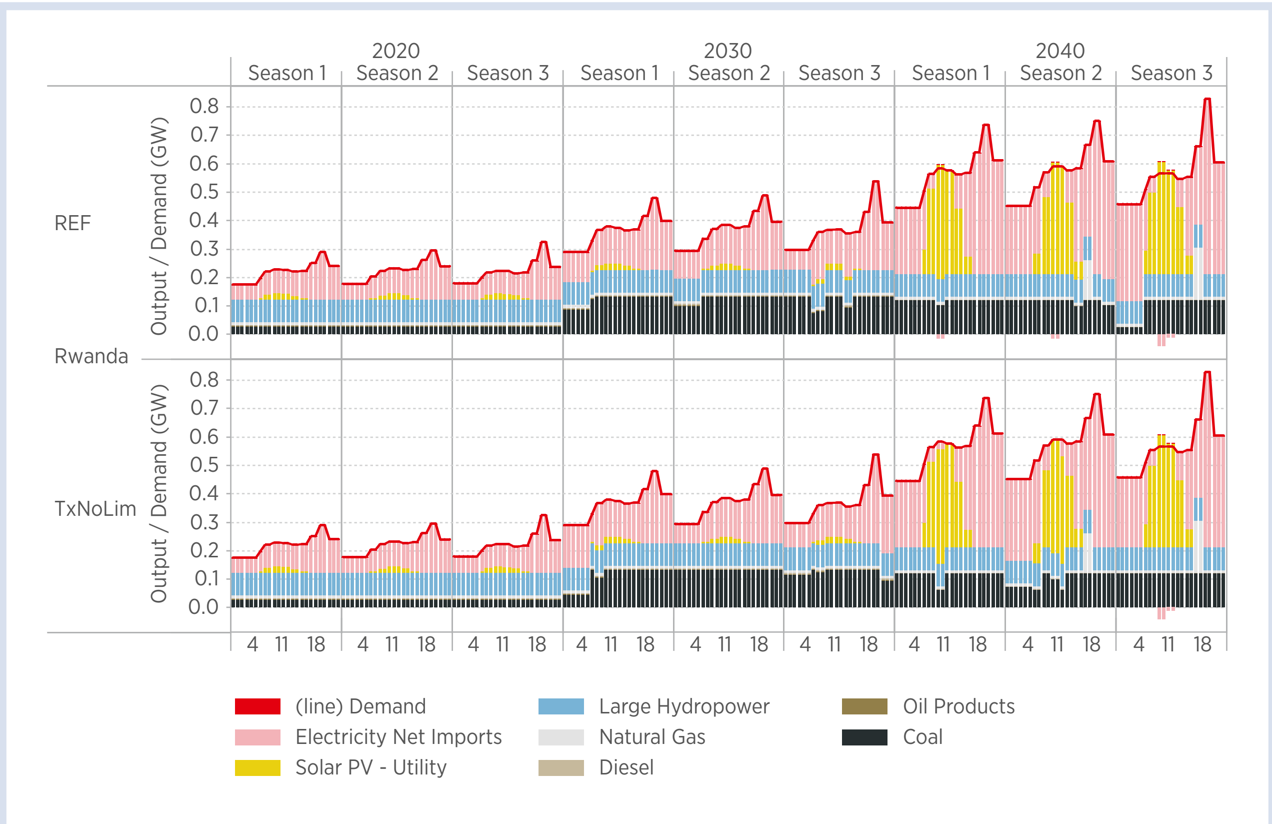
Mozambique



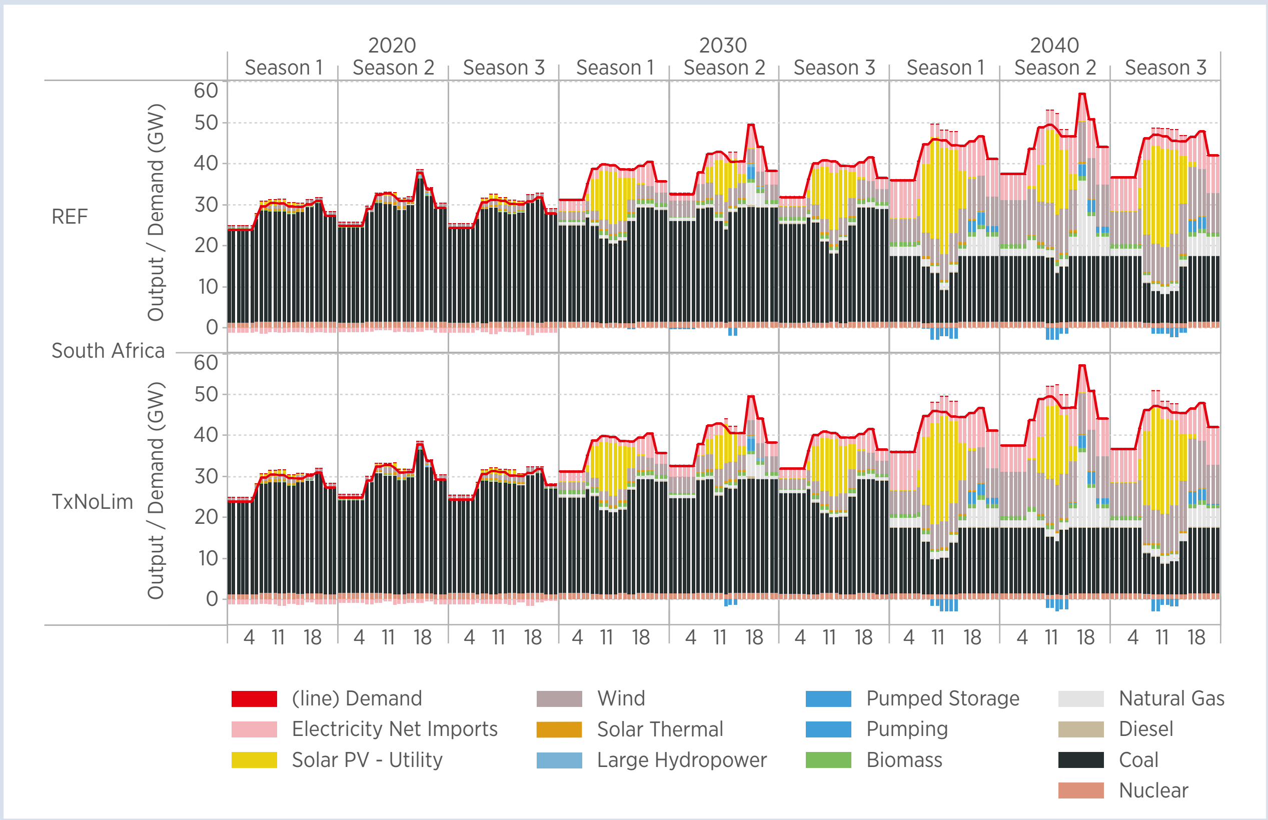
Namibia



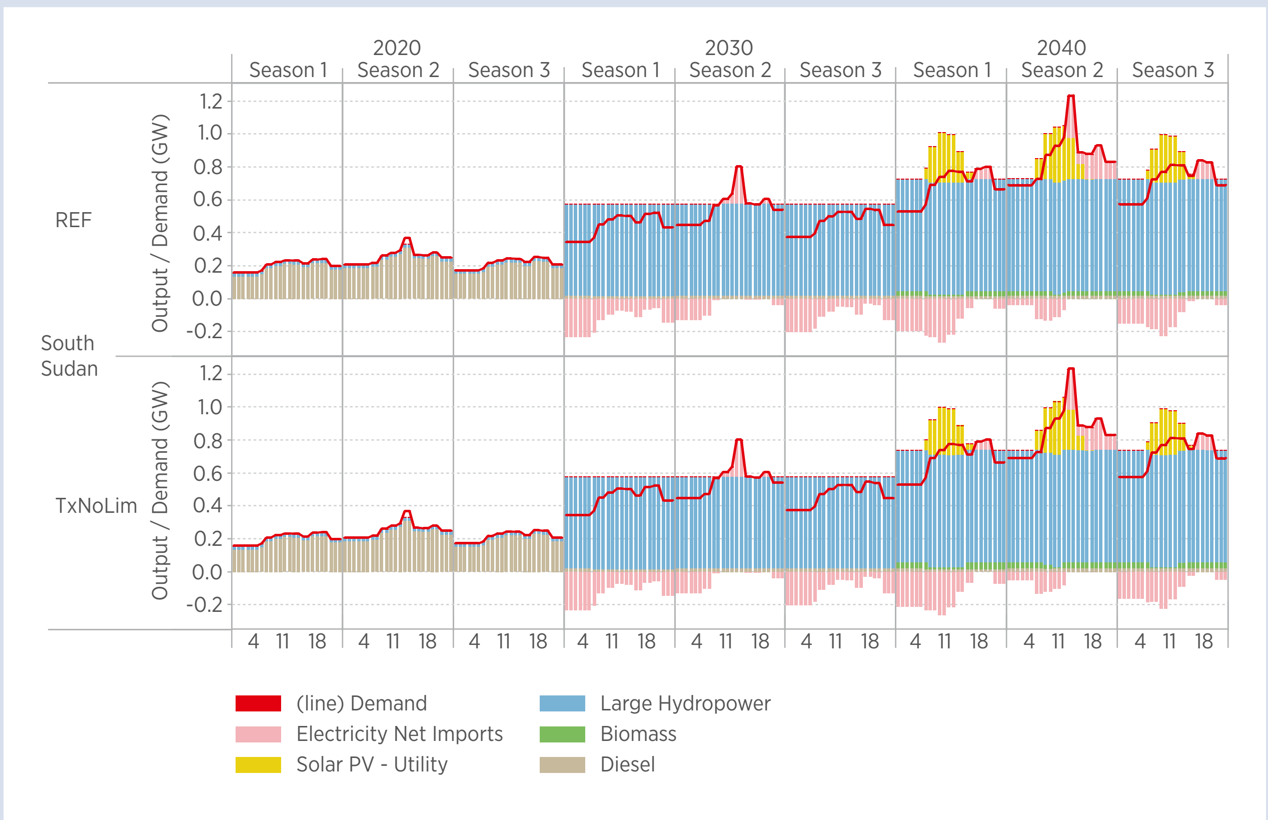
Rwanda



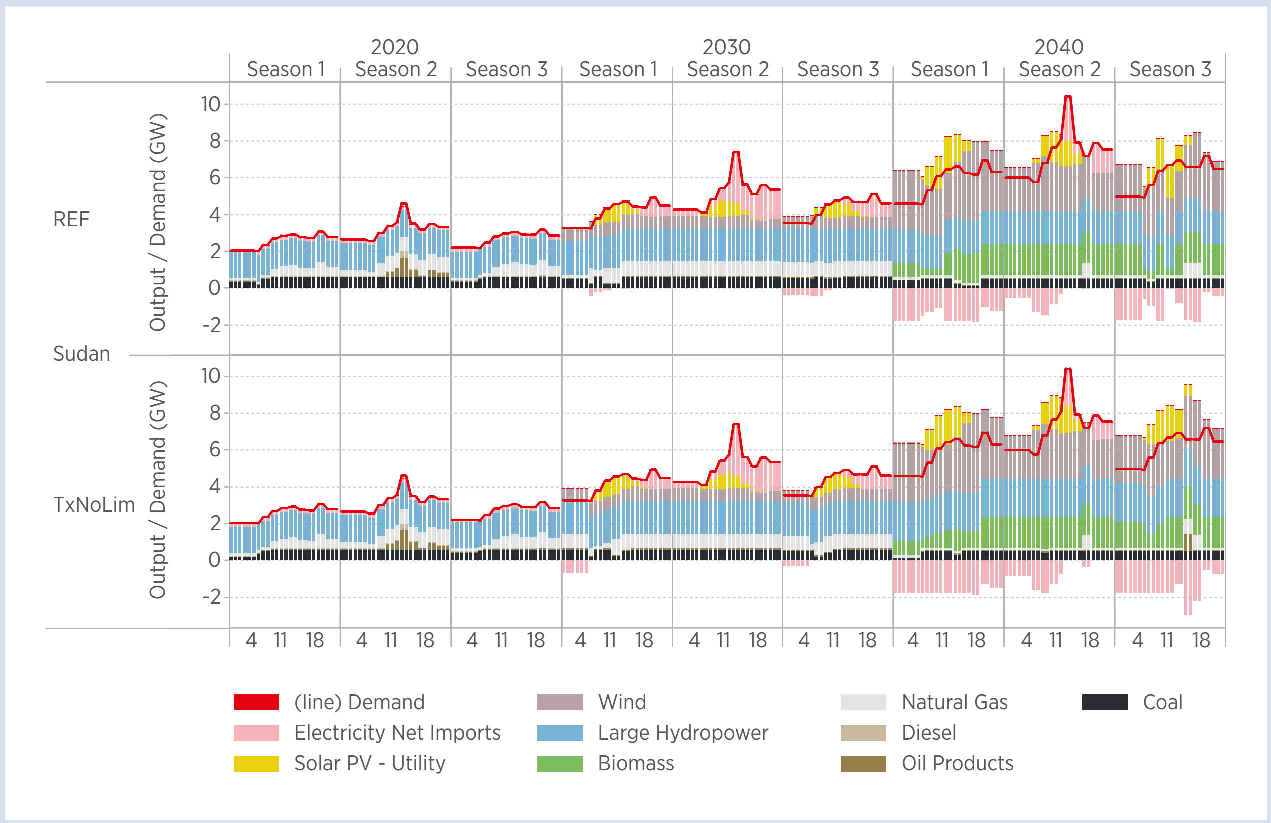
South Africa



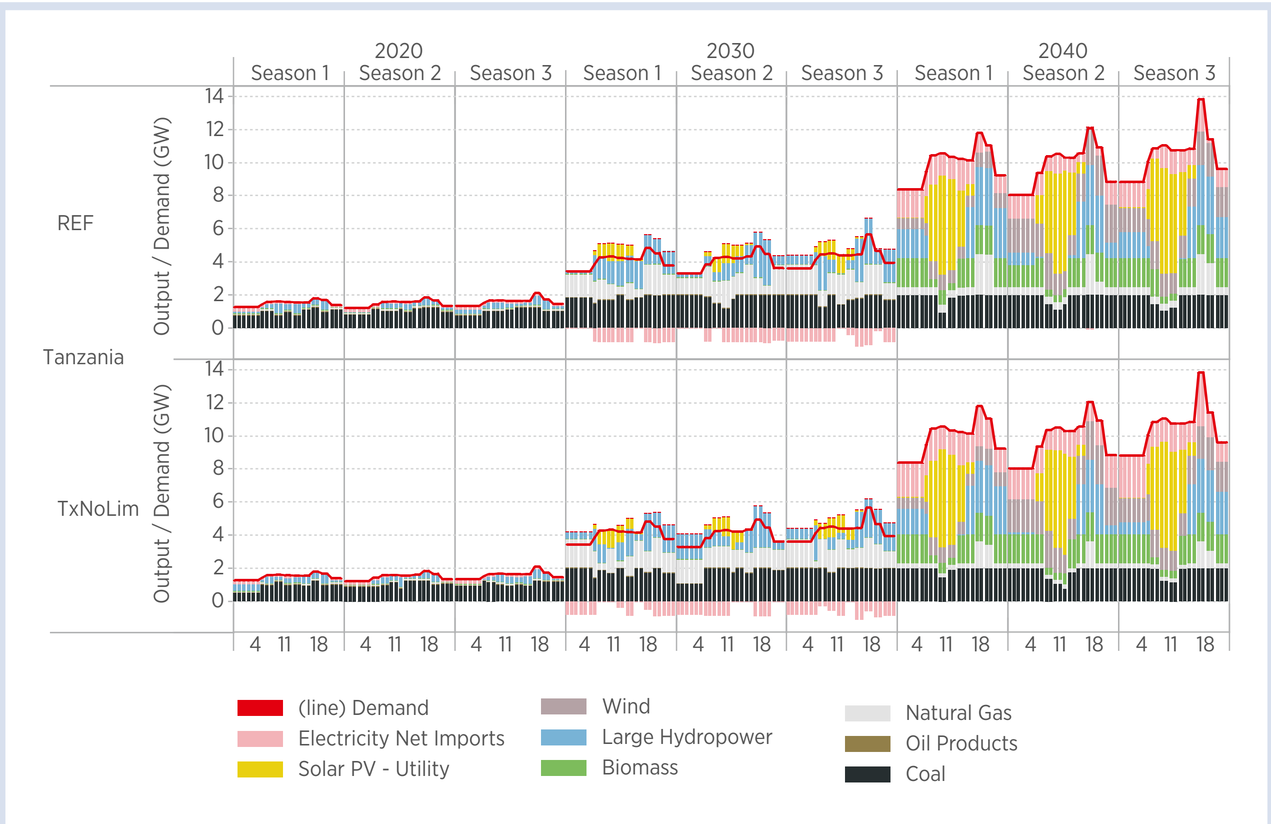
South Sudan



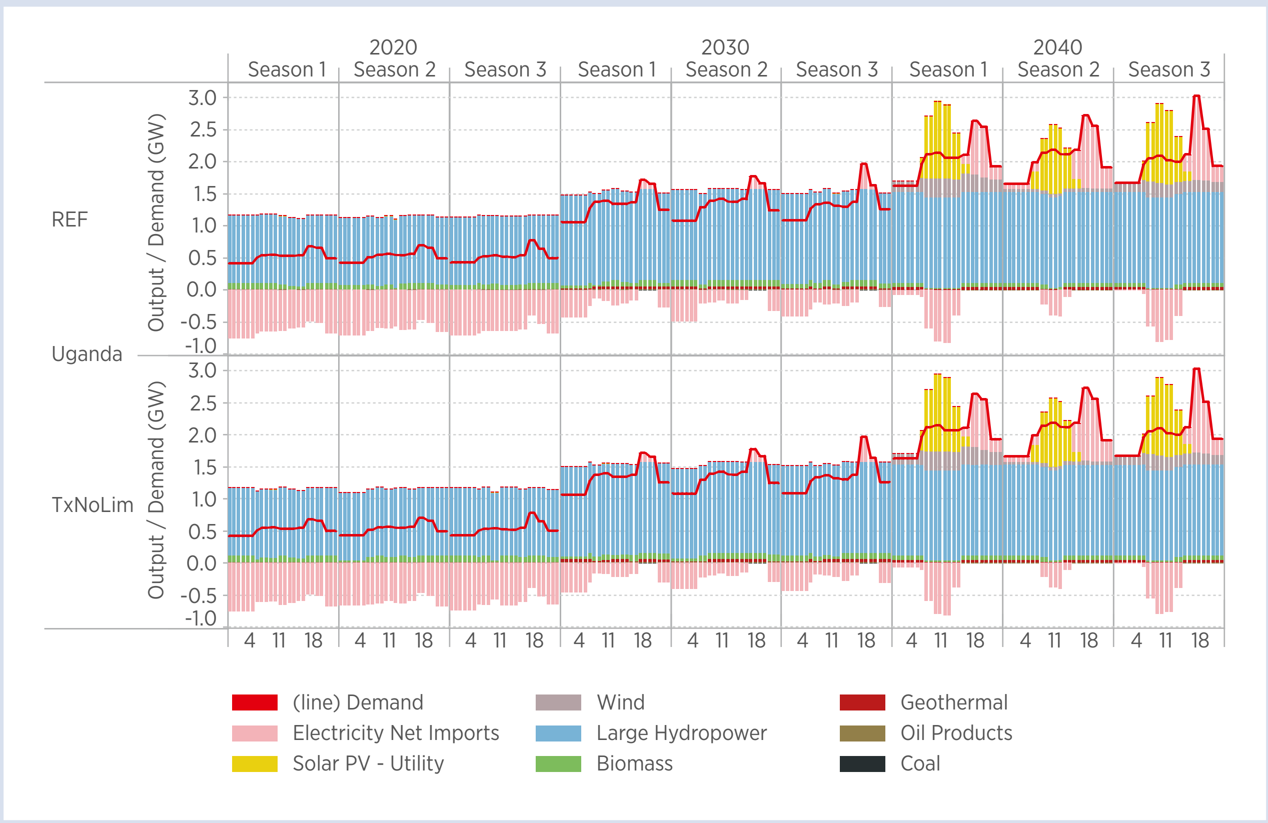
Sudan



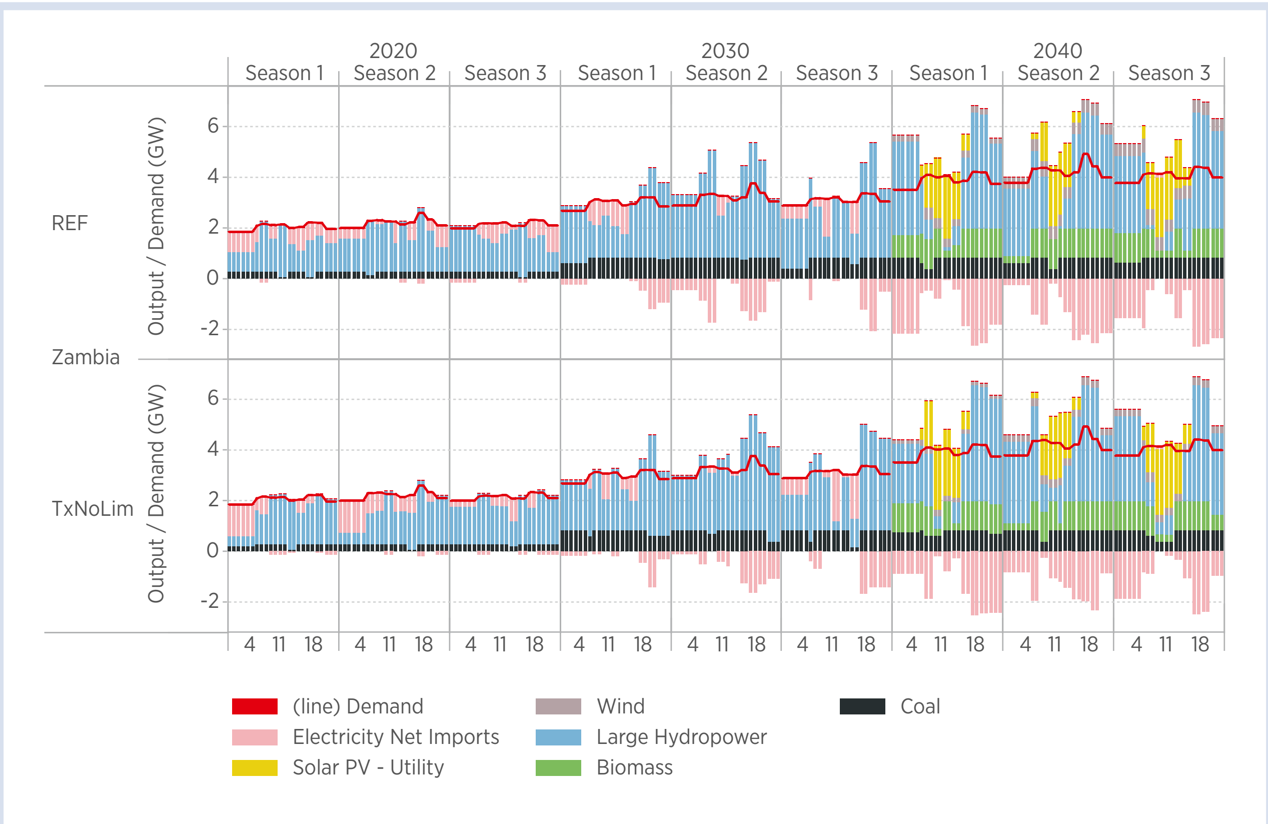
Tanzania



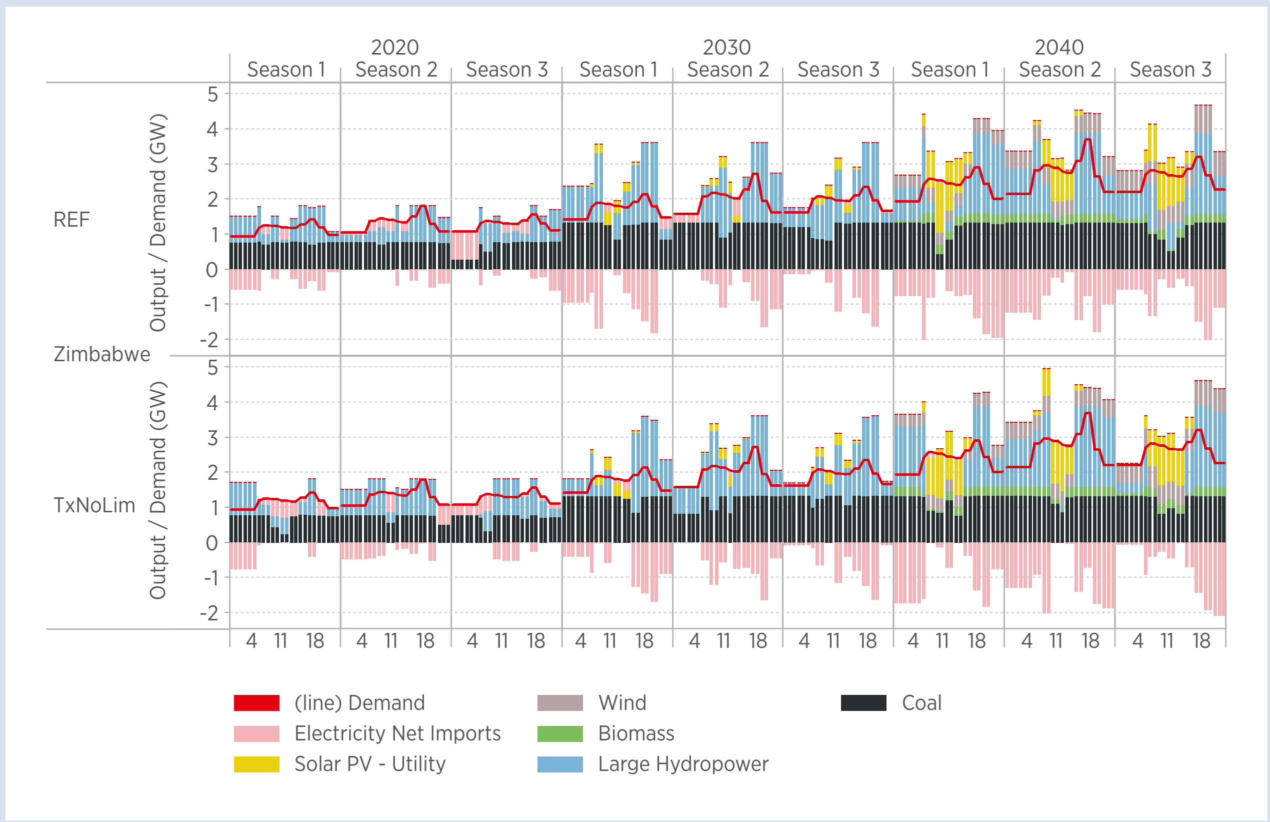
Uganda



Zambia



Zimbabwe



2020
2030
2040
Season 1
Season 2
Season 3
REF
TxNoLim
Zimbabwe
Output / Demand (GW)
5
4
3
2
1
0
-1
-2
4
11
18
(line) Demand
Electricity Net Imports
Solar PV - Utility
Wind
Biomass
Large Hydropower
Coal

7.6 Technology parameters and modelled capacities for zones

This section provides additional details regarding the solar PV and wind zones. The geographical coordinates, capacity factors and maximum technical capacities were assessed in the MapRE study (IRENA and LBNL, 2015a; 2015b).

7.6.1 Solar PV

Country	Zone	Longitude	Latitude	Average capacity factor	Max. capacity	Installed capacity (MW)					
						VRELim	REF	VREHigh	HYDry	HYDel	TxNoLim
Angola	AL	13.2300	-15.7297	0.25	225	-	225	225	225	225	225
Angola	AO	13.2218	-15.4566	0.25	35	-	-	35	35	35	-
Angola	AT	14.2540	-15.0931	0.26	62	62	62	62	62	62	62
Angola	AU	12.9765	-15.0227	0.24	32	32	32	32	32	32	32
Angola	AW	13.9287	-15.0399	0.26	80	80	80	80	80	80	80
Angola	AX	12.6851	-14.9911	0.24	102	102	102	102	102	102	102
Angola	AY	14.4049	-15.0375	0.26	98	98	98	98	98	98	98
Angola	AZ	14.1574	-14.9759	0.26	104	104	104	104	104	104	104
Angola	BA	12.7641	-14.7840	0.24	35	35	35	35	35	35	35
Angola	BB	14.4942	-14.6619	0.26	33	33	33	33	33	33	33
Angola	BC	14.6591	-14.7187	0.26	56	56	56	56	56	56	56
Angola	BE	12.8623	-14.5988	0.24	66	-	66	66	66	66	66
Angola	CC	14.3836	-17.3321	0.26	62	62	62	62	62	62	62
Angola	DC	14.1790	-17.3968	0.25	191	191	191	191	191	191	191
Angola	DJ	14.7287	-17.3903	0.26	167	167	167	167	167	167	167
Angola	EX	14.0194	-17.2127	0.25	184	184	184	184	184	184	184
Angola	FA	14.0057	-17.0424	0.25	38	38	38	38	38	38	38
Angola	FE	13.6741	-17.2068	0.25	178	-	178	178	178	178	178
Angola	FF	19.4360	-17.8464	0.25	246	246	246	246	246	246	246
Angola	FG	14.3127	-16.9303	0.26	32	32	32	32	32	32	32
Angola	FI	20.1219	-17.9004	0.25	81	81	81	81	81	81	81
Angola	FJ	13.3695	-16.8783	0.25	109	-	109	109	109	109	109
Angola	G	15.0043	-16.7151	0.26	126	126	126	126	126	126	126
Angola	L	18.8621	-17.7970	0.25	150	150	150	150	150	150	150
Angola	M	13.9934	-16.5978	0.26	41	41	41	41	41	41	41
Botswana	DZ	27.5458	-21.3799	0.24	814	814	814	666	814	814	814
Botswana	J	25.6267	-24.7970	0.24	574	181	189	-	128	189	189
Burundi	C	29.3352	-3.1715	0.23	40	-	-	18	-	-	-
Burundi	E	30.4224	-3.2537	0.24	177	-	177	177	177	177	177

Country	Zone	Longitude	Latitude	Average capacity factor	Max. capacity	Installed capacity (MW)					
						VRELim	REF	VREHigh	HYDry	HYDel	TxNoLim
Burundi	G	30.5520	-2.9714	0.24	82	-	31	82	31	31	31
DRC	A	23.9313	-8.8628	0.23	754	-	754	754	754	754	754
DRC	AB	22.9995	-5.5889	0.22	97	-	-	-	97	-	-
DRC	AO	27.4371	-11.6798	0.25	96	200	200	200	200	200	200
DRC	B	24.7065	-8.4729	0.23	103	-	103	103	103	103	103
DRC	C	25.1956	-8.5662	0.23	137	-	137	137	137	137	137
DRC	D	23.6360	-8.5234	0.23	161	-	161	131	161	161	161
DRC	E	24.5321	-8.3500	0.23	347	-	347	347	347	347	347
DRC	F	25.1036	-8.5577	0.23	592	-	592	592	592	592	592
DRC	G	25.2585	-7.7487	0.23	265	-	74	-	265	74	74
DRC	H	25.0552	-7.6175	0.23	642	-	-	-	56	-	-
DRC	L	24.4792	-6.9154	0.22	98	-	98	98	98	98	98
DRC	O	27.2516	-10.6431	0.24	107	200	200	200	200	200	200
DRC	S	19.9701	-6.3067	0.22	91	-	91	91	91	91	91
DRC	T	26.5193	-10.3456	0.24	262	200	262	262	262	262	262
DRC	Z	26.9554	-10.1835	0.24	205	-	205	205	205	205	205
Djibouti	E	42.5890	11.9503	0.24	1 270	35	35	35	35	35	35
Egypt	AA	32.9839	30.2385	0.22	2 620	-	2 620	2 620	2 620	2 620	2 620
Egypt	AK	32.9336	29.6295	0.22	4 740	-	4 740	4 740	4 740	4 740	4 740
Egypt	CV	30.6824	27.8857	0.22	1 100	750	750	750	750	750	750
Egypt	CW	30.5815	28.2952	0.22	1 740	-	1 740	1 740	1 740	1 740	1 740
Egypt	EC	30.6920	27.8664	0.22	980	-	980	980	980	980	980
Egypt	ED	31.6247	26.3640	0.22	1 320	-	1 320	-	1 320	1 320	1 320
Egypt	EJ	31.1510	27.1245	0.22	2 860	-	2 860	-	2 860	2 860	2 860
Egypt	EL	30.9747	27.1479	0.22	2 290	-	2 290	2 290	2 290	2 290	2 290
Egypt	FG	32.1295	26.4462	0.22	4 240	-	-	-	-	-	-
Egypt	FV	32.8196	23.8609	0.22	829	-	829	829	829	829	829
Egypt	FX	32.7371	24.2655	0.22	838	-	838	838	838	838	838
Egypt	GA	32.6237	23.9579	0.23	2 140	2 140	2 140	2 140	2 140	2 140	2 140
Egypt	GD	32.6940	24.3166	0.23	3 010	-	3 010	3 010	3 010	3 010	3 010
Egypt	GG	32.3367	24.2037	0.22	2 350	-	2 350	2 350	2 350	2 350	2 350
Egypt	GI	32.7180	24.2841	0.23	2 110	-	2 110	2 110	2 110	2 110	2 110
Egypt	JA	33.1664	25.5980	0.22	1 590	-	1 590	399	1 590	1 590	1 590
Egypt	JG	33.1945	24.3789	0.23	1 400	721	1 400	1 400	1 400	1 400	1 400
Egypt	JH	33.1514	25.8008	0.22	1 130	-	1 130	1 130	1 130	1 130	1 130
Egypt	JN	33.0966	23.7457	0.23	848	-	848	848	848	848	848
Egypt	JS	33.0318	25.9326	0.22	1 320	-	1 320	1 320	1 320	1 320	1 320
Egypt	KE	32.9306	26.2589	0.22	1 820	-	1 820	1 820	1 820	1 820	1 820

Country	Zone	Longitude	Latitude	Average capacity factor	Max. capacity	Installed capacity (MW)					
						VRELim	REF	VREHigh	HYDry	HYDel	TxNoLim
Egypt	KH	33.4823	23.9236	0.23	2 100	-	2 100	2 100	2 100	2 100	2 100
Egypt	KT	33.4286	24.2818	0.23	3 410	3 410	3 410	3 410	3 410	3 410	3 410
Egypt	KW	32.9004	23.9309	0.23	2 920	-	2 920	2 920	2 920	2 920	2 920
Egypt	KZ	32.9427	25.5030	0.22	3 370	-	71	-	71	71	71
Egypt	MP	32.3148	29.7058	0.22	1 950	-	1 950	1 950	1 950	1 950	1 950
Egypt	MT	31.9389	26.4456	0.21	989	-	989	-	989	989	989
Egypt	NU	32.4952	29.8583	0.21	954	-	954	954	954	954	954
Eswatini	B	31.6498	-26.4032	0.20	32	-	40	40	40	40	40
Eswatini	D	31.6562	-26.9321	0.20	32	-	103	6	47	103	103
Eswatini	E	31.8845	-26.4952	0.20	32	-	87	87	87	87	87
Ethiopia	AS	41.5838	9.7533	0.25	2 150	2 150	2 150	2 150	2 150	2 150	2 150
Ethiopia	AX	41.9133	9.9700	0.25	1 780	-	1 780	1 780	1 780	1 780	1 780
Ethiopia	BC	41.2881	9.5026	0.25	2 470	-	2 470	2 470	2 470	2 470	2 470
Ethiopia	BU	41.8493	9.5705	0.25	2 420	2 420	2 420	2 420	2 420	2 420	2 420
Ethiopia	C	39.3495	8.6308	0.26	238	238	238	238	238	238	238
Ethiopia	CO	38.9747	12.9974	0.26	1 180	1 180	1 180	1 180	1 180	1 180	1 180
Ethiopia	CQ	39.5154	13.1395	0.27	672	672	672	672	672	672	672
Ethiopia	CV	39.0273	13.7420	0.27	807	807	807	807	807	807	807
Ethiopia	D	39.8352	8.5565	0.26	379	379	379	379	379	379	379
Ethiopia	E	39.4682	8.8367	0.26	182	182	182	182	182	182	182
Ethiopia	GG	39.1987	8.2070	0.27	142	142	142	142	142	142	142
Ethiopia	GH	38.6745	8.2853	0.27	200	200	200	200	200	200	200
Ethiopia	GI	39.4565	8.4433	0.26	103	103	103	103	103	103	103
Ethiopia	GJ	38.9175	8.5857	0.27	102	102	102	102	102	102	102
Ethiopia	N	39.3805	10.4104	0.28	107	107	107	107	107	107	107
Ethiopia	S	37.1567	11.5413	0.27	109	109	109	109	109	109	109
Kenya	FE	35.8918	0.2696	0.27	139	139	-	139	-	-	-
Lesotho	J	27.1985	-29.9198	0.24	312	236	228	144	211	228	228
Malawi	A	35.2086	-16.6968	0.23	41	41	41	41	41	41	41
Malawi	B	34.8429	-15.4559	0.23	72	72	72	72	72	72	72
Malawi	C	35.0002	-14.8193	0.23	35	35	35	35	35	35	35
Malawi	D	35.7148	-14.9030	0.23	204	204	204	204	204	204	204
Malawi	E	35.6155	-14.4715	0.23	44	-	44	44	-	44	44
Malawi	F	33.7339	-14.0602	0.24	38	38	38	38	38	38	38
Malawi	G	34.8676	-16.5675	0.22	138	138	138	138	138	138	138
Malawi	H	33.4557	-13.7081	0.24	34	34	34	34	34	34	34
Malawi	I	34.5482	-13.7130	0.24	44	44	44	44	44	44	44
Malawi	J	33.7898	-13.5049	0.24	100	100	100	100	100	100	100

Country	Zone	Longitude	Latitude	Average capacity factor	Max. capacity	Installed capacity (MW)					
						VRELim	REF	VREHigh	HYDry	HYDel	TxNoLim
Malawi	K	33.3665	-13.2785	0.24	50	50	50	50	50	50	50
Malawi	L	33.6964	-13.2259	0.24	235	235	235	235	235	235	235
Malawi	M	33.5929	-12.8486	0.24	86	86	86	86	86	86	86
Malawi	N	33.4986	-12.3303	0.25	44	44	44	44	44	44	44
Malawi	O	34.7001	-16.1071	0.23	90	90	90	90	90	90	90
Mozambique	K	33.7731	-16.4713	0.23	966	966	966	966	966	966	966
Mozambique	L	34.1316	-16.1744	0.22	955	30	544	30	280	544	466
Mozambique	M	33.2953	-16.1250	0.23	658	-	658	-	658	658	658
Mozambique	N	33.6880	-15.8719	0.22	274	30	30	30	30	30	30
Mozambique	W	35.3229	-13.2587	0.23	664	664	664	381	664	664	664
Namibia	AL	16.9765	-22.4355	0.25	1 910	1 085	854	708	832	895	879
Rwanda	G	29.5792	-2.0892	0.23	59	-	59	59	59	59	59
Rwanda	H	29.8259	-2.2908	0.24	271	-	261	261	261	261	261
South Africa	AD	17.8942	-29.7358	0.24	881	881	881	881	881	881	881
South Africa	AF	17.2101	-29.5099	0.23	1 150	-	-	1 150	-	-	-
South Africa	AH	17.7910	-29.8976	0.24	507	507	507	507	507	507	507
South Africa	AK	17.3516	-29.6293	0.23	717	-	-	717	-	-	-
South Africa	AO	18.8202	-29.1916	0.25	3 200	3 200	3 200	3 200	3 200	3 200	3 200
South Africa	AR	18.1390	-29.6507	0.25	5 830	5 830	5 830	5 830	5 830	5 830	5 830
South Africa	AT	18.9757	-29.5863	0.25	1 280	1 280	1 280	1 280	1 280	1 280	1 280
South Africa	AZ	21.8822	-28.8329	0.24	576	576	576	576	576	576	576
South Africa	BE	21.9798	-29.0223	0.24	1 750	1 750	1 338	1 750	1 338	1 338	1 338
South Africa	BK	22.1072	-28.8285	0.24	1 760	-	-	1 760	-	-	-
South Africa	D	24.7966	-28.7357	0.24	1 820	1 820	1 820	1 820	1 820	1 820	1 820
South Africa	G	25.7696	-28.7592	0.24	985	985	985	985	985	985	985
South Africa	I	25.4224	-28.7640	0.24	902	902	902	902	902	902	902
South Africa	J	25.1926	-28.9106	0.24	3 410	3 410	3 410	3 410	3 410	3 410	3 410
South Africa	K	24.7623	-29.1615	0.24	5 500	592	3 301	5 500	5 087	3 405	3 123
South Africa	Q	24.9433	-27.2391	0.24	818	818	818	818	818	818	818
South Africa	V	24.6159	-27.1878	0.24	3 950	3 950	3 950	3 950	3 950	3 950	3 950
South Africa	W	25.2218	-27.0201	0.24	2 970	2 970	2 970	2 970	2 970	2 970	2 970
Sudan	IC	22.4856	13.1783	0.26	2 160	2 160	2 160	2 160	2 160	2 160	2 160
Tanzania	AD	33.6873	-4.1886	0.26	2 900	2 900	2 694	1 823	2 879	2 694	2 694
Tanzania	AF	33.1013	-3.8787	0.26	3 090	3 090	3 090	3 090	3 090	3 090	3 090
Tanzania	AT	35.7205	-7.5623	0.26	174	174	174	174	174	174	174
Tanzania	BA	35.5503	-6.4850	0.26	1 110	815	-	-	-	-	-
Tanzania	BB	35.7910	-6.2560	0.26	1 470	1 470	1 470	347	1 470	1 470	1 470
Uganda	AB	32.3129	3.0655	0.25	75	-	75	75	75	75	75

Country	Zone	Longitude	Latitude	Average capacity factor	Max. capacity	Installed capacity (MW)					
						VRELim	REF	VREHigh	HYDry	HYDel	TxNoLim
Uganda	AM	32.1733	3.0440	0.25	284	-	284	284	284	284	284
Uganda	J	33.0761	2.5105	0.26	47	-	-	47	-	-	-
Uganda	K	32.1129	2.4107	0.25	185	20	185	185	125	185	185
Uganda	M	33.3850	2.3680	0.26	520	-	520	520	520	520	520
Uganda	R	32.0298	2.7523	0.25	35	-	35	35	35	35	35
Uganda	S	32.5841	2.6821	0.25	102	-	102	102	102	102	102
Uganda	T	32.9983	2.6875	0.25	114	-	114	114	114	114	114
Uganda	V	32.7665	2.8388	0.25	53	-	17	53	-	15	-
Uganda	Y	32.0193	3.0309	0.25	30	-	-	30	-	-	-
Uganda	Z	32.8726	2.7969	0.25	106	-	106	106	106	106	106
Zambia	G	28.1898	-15.3814	0.24	142	-	-	-	-	-	-
Zambia	K	26.0772	-17.9617	0.24	860	860	860	361	860	860	860
Zambia	L	26.1890	-17.8477	0.24	499	288	-	-	-	-	40
Zambia	M	25.6245	-17.4366	0.24	386	386	265	-	-	320	386
Zambia	T	31.8962	-10.5500	0.25	176	176	176	176	176	176	176
Zambia	W	26.6800	-17.3051	0.25	1 150	1 150	1 150	1 150	1 150	1 150	1 150
Zambia	Y	26.7046	-17.6154	0.24	719	719	719	-	680	719	719
Zambia	Z	28.0890	-16.2319	0.25	92	92	92	92	92	92	92
Zimbabwe	AO	28.1683	-20.4926	0.25	1 600	1 600	1 311	143	-	1 255	1 311
Zimbabwe	AZ	29.5649	-19.8297	0.25	2 310	146	7	802	1 638	114	-
Zimbabwe	BF	29.9970	-19.2808	0.25	111	111	111	111	111	111	111
Zimbabwe	X	31.0892	-18.1346	0.25	316	316	316	316	316	316	316

7.6.2 Wind

Country	Zone	Longitude	Latitude	Average capacity factor	Max. capacity	Installed capacity (MW)					
						VRELim	REF	VREHigh	HYDry	HYDel	TxNoLim
Botswana	O	26.8484	-20.7563	0.31	1 440	-	-	1 440	727	-	-
DRC	A	28.6760	-4.6468	0.31	182	-	-	182	-	-	-
Dem. Rep. of the Congo	B	24.7065	-8.4729	0.29	80	-	-	-	-	-	-
Dem. Rep. of the Congo	C	29.0868	-6.9885	0.30	296	-	-	296	-	-	-
Dem. Rep. of the Congo	D	29.1105	-6.7729	0.33	100	-	-	100	-	-	-
Dem. Rep. of the Congo	E	28.9601	-6.5788	0.28	626	-	-	626	-	-	-
Djibouti	E	42.8658	12.4548	0.39	824	318	425	600	425	405	425
Egypt	AA	32.5650	25.8602	0.33	1 220	1 510	1 510	1 510	1 510	1 510	1 510
Egypt	AB	32.6406	26.0496	0.29	524	-	-	524	-	-	-
Egypt	AE	32.3473	25.3834	0.31	1 640	-	1 640	1 640	1 640	1 640	1 640
Egypt	B	32.4514	24.1481	0.29	565	-	-	565	-	-	-
Egypt	DF	31.7586	26.2079	0.29	364	-	-	364	-	-	-
Egypt	DG	31.8634	26.2224	0.29	433	-	-	433	-	-	-
Egypt	DX	31.3295	26.3015	0.32	1 410	-	-	1 410	-	-	-
Egypt	DY	31.6106	26.2881	0.30	395	-	-	395	-	-	-
Egypt	E	35.4128	24.1964	0.40	2 160	-	2 160	2 160	2 160	2 160	2 160
Egypt	EE	33.8184	27.1139	0.39	904	700	700	700	700	700	700
Egypt	EF	33.6745	27.3956	0.38	845	845	845	845	845	845	845
Egypt	EM	31.1835	27.4452	0.29	361	-	-	361	-	-	-
Egypt	EN	31.2786	27.4934	0.30	477	-	-	477	-	-	-
Egypt	ES	32.2801	27.0561	0.33	2 760	-	2 760	2 760	2 760	2 760	2 760
Egypt	ET	32.0429	26.7312	0.32	1 350	-	1 350	1 350	1 350	1 350	1 350
Egypt	EW	32.5674	26.5853	0.33	1 100	-	-	1 100	-	-	-
Egypt	EY	32.2824	26.3043	0.33	450	-	450	450	450	450	450
Egypt	EZ	32.6680	26.4146	0.30	1 670	-	-	1 670	-	-	-
Egypt	FC	31.8676	26.4074	0.31	1 200	-	1 200	1 200	1 200	1 200	1 200
Egypt	FG	32.1295	26.4462	0.33	1 200	-	1 200	1 200	1 200	1 200	1 200
Egypt	FI	34.5128	28.5450	0.39	141	141	141	141	141	141	141
Egypt	FK	32.8512	28.6453	0.41	588	588	588	588	588	588	588
Egypt	FL	33.5010	27.9568	0.45	432	432	432	432	432	432	432
Egypt	FQ	33.4921	27.7740	0.40	1 110	1 110	1 110	1 110	1 110	1 110	1 110
Egypt	FR	32.9965	27.9069	0.40	1 540	1 540	1 540	1 540	1 540	1 540	1 540
Egypt	FS	32.8948	28.4131	0.40	750	750	750	750	750	750	750
Egypt	FU	32.9142	28.2923	0.40	1 470	1 470	1 470	1 470	1 470	1 470	1 470

Country	Zone	Longitude	Latitude	Average capacity factor	Max. capacity	Installed capacity (MW)					
						VRELim	REF	VREHigh	HYDry	HYDel	TxNoLim
Egypt	FY	33.0859	28.2205	0.43	2 340	2 340	2 340	2 340	2 340	2 340	2 340
Egypt	FZ	32.9332	28.3262	0.42	804	804	804	804	804	804	804
Egypt	GH	29.8936	29.4254	0.36	1 370	-	1 370	1 370	1 370	1 370	1 370
Egypt	GL	30.8727	29.9075	0.30	1 070	-	-	1 070	-	-	-
Egypt	GN	30.9396	29.7704	0.32	1 400	-	1 400	1 400	1 400	1 400	1 400
Egypt	GU	31.3435	29.9726	0.29	3 060	-	-	3 060	-	-	-
Egypt	GV	31.4159	29.5758	0.30	877	-	-	877	-	-	-
Egypt	GW	32.4641	29.1445	0.40	926	926	926	926	926	926	926
Egypt	GX	32.6641	29.1014	0.44	547	547	547	547	547	547	547
Egypt	HA	32.2775	29.4757	0.32	652	-	652	652	652	652	652
Egypt	HC	32.1253	29.4508	0.33	2 750	-	2 750	2 750	2 750	2 750	2 750
Egypt	HE	32.4278	30.0890	0.30	2 110	-	2 110	2 110	2 110	2 110	2 110
Egypt	HF	32.3207	29.3342	0.36	1 580	-	1 580	1 580	1 580	1 580	1 580
Egypt	HH	31.5597	29.1856	0.35	731	-	731	731	731	731	731
Egypt	HJ	33.0297	29.3366	0.38	905	-	905	905	905	905	905
Egypt	HM	33.1773	29.3371	0.41	492	492	492	492	492	492	492
Egypt	HS	34.4315	28.6416	0.38	711	711	711	711	711	711	711
Egypt	HU	33.3755	28.4535	0.39	733	733	733	733	733	733	733
Egypt	HW	32.7193	29.6777	0.29	2 160	-	-	2 160	-	-	-
Egypt	HZ	32.7952	29.7662	0.35	2 470	-	2 470	2 470	2 470	2 470	2 470
Egypt	IA	33.1730	29.1908	0.39	1 100	1 100	1 100	1 100	1 100	1 100	1 100
Egypt	J	32.8097	25.3613	0.29	1 060	-	-	1 060	-	-	-
Egypt	K	32.9529	25.2960	0.30	601	-	-	601	-	-	-
Eswatini	J	31.9575	-26.3977	0.31	121	-	121	121	121	121	121
Eswatini	K	32.0608	-26.6337	0.28	206	-	-	206	141	-	-
Ethiopia	BP	38.5766	7.8153	0.30	555	-	-	555	-	-	-
Ethiopia	BQ	39.0408	8.0994	0.32	647	443	443	647	443	443	443
Ethiopia	BR	39.4699	8.5801	0.26	82	-	-	82	-	-	-
Ethiopia	BS	39.1751	8.8480	0.33	409	-	409	409	409	409	409
Ethiopia	BT	39.1386	8.5612	0.32	410	-	-	410	410	-	410
Ethiopia	BU	39.4697	9.3034	0.30	356	-	-	356	-	-	-
Ethiopia	CC	39.6100	9.8531	0.31	769	-	-	769	-	-	-
Ethiopia	CD	39.6539	10.4421	0.31	780	-	-	780	-	-	-
Ethiopia	CK	37.8922	5.0576	0.34	717	-	717	717	717	717	717
Ethiopia	CM	37.5541	12.4866	0.30	297	-	-	297	-	-	-
Ethiopia	CT	39.2079	13.2465	0.27	203	-	-	203	-	83	-
Ethiopia	CX	39.6866	14.0337	0.29	175	-	-	175	-	-	-
Ethiopia	Q	42.0644	6.1628	0.42	529	529	529	529	529	529	529

Country	Zone	Longitude	Latitude	Average capacity factor	Max. capacity	Installed capacity (MW)					
						VRELim	REF	VREHigh	HYDry	HYDel	TxNoLim
Kenya	DM	36.7337	2.3130	0.49	872	872	872	872	872	872	872
Kenya	DP	36.7472	2.4945	0.62	400	250	250	250	250	250	250
Kenya	DR	36.6551	1.7349	0.44	494	215	494	494	494	494	494
Kenya	ET	38.0955	2.5852	0.51	530	530	530	530	530	530	530
Kenya	EZ	37.5605	3.4271	0.59	675	675	675	675	675	675	675
Kenya	H	36.6203	-1.4829	0.34	1 380	150	150	150	150	150	150
Lesotho	C	27.3012	-29.9073	0.28	154	-	68	154	112	68	68
Lesotho	D	27.2768	-29.9455	0.27	182	-	-	182	-	-	-
Malawi	G	33.1578	-9.5978	0.36	134	-	-	134	-	-	-
Malawi	H	32.9826	-9.4072	0.37	63	-	63	63	63	63	63
Malawi	I	34.8538	-15.6986	0.29	133	-	133	133	133	127	-
Malawi	J	34.9127	-15.8372	0.30	110	-	110	110	110	110	110
Malawi	K	35.0917	-15.6456	0.30	54	-	54	54	54	54	-
Malawi	O	33.7328	-11.4872	0.35	330	-	330	330	330	330	330
Malawi	Q	33.6559	-11.6626	0.36	177	177	177	177	177	177	177
Mozambique	AC	33.5982	-16.4980	0.30	1 750	-	-	1 750	734	-	-
Mozambique	AI	33.3342	-16.1249	0.27	74	-	-	74	-	-	-
Mozambique	Z	33.6270	-16.3978	0.28	435	-	-	435	-	-	-
Namibia	BJ	14.5616	-22.7194	0.33	109	-	109	109	109	109	109
Namibia	H	17.8418	-27.7332	0.33	627	-	627	627	627	627	627
Namibia	I	17.6018	-27.9105	0.32	560	-	108	560	211	1	24
South Africa	AD	29.6840	-27.6830	0.34	903	903	903	903	903	903	903
South Africa	AF	29.6742	-27.7017	0.34	795	795	795	795	795	795	795
South Africa	AG	29.3383	-28.3641	0.33	2 880	2 880	2 880	2 880	2 880	2 880	2 880
South Africa	AH	28.8010	-28.6478	0.32	3 130	-	3 130	3 130	3 130	3 130	3 130
South Africa	AP	25.7173	-33.7518	0.37	100	100	100	100	100	100	100
South Africa	BI	22.7494	-32.0927	0.35	1 520	1 520	1 520	1 520	1 520	1 520	1 520
South Africa	CT	22.6906	-32.1952	0.35	1 200	1 200	1 200	1 200	1 200	1 200	1 200
South Africa	FE	21.6837	-34.3273	0.35	1 320	1 320	1 320	1 320	1 320	1 320	1 320
South Africa	FK	26.8429	-31.7960	0.37	713	713	713	713	713	713	713
South Africa	FW	26.9161	-31.4998	0.38	114	114	114	114	114	114	114
South Africa	GA	26.7842	-31.9128	0.34	1 770	1 770	1 770	1 770	1 770	1 770	1 770
South Africa	GO	25.9570	-32.6807	0.36	832	832	832	832	832	832	832
South Africa	GU	26.2949	-32.5579	0.37	1 780	1 780	1 780	1 780	1 780	1 780	1 780
South Africa	GW	25.9129	-32.5091	0.37	378	378	378	378	378	378	378
South Africa	GX	25.8984	-32.9559	0.37	862	1 450	1 450	1 450	1 450	1 450	1 450
South Africa	GY	25.6142	-32.6857	0.36	780	780	780	780	780	780	780
South Africa	HC	25.9766	-32.6954	0.35	1 370	1 370	1 370	1 370	1 370	1 370	1 370

Country	Zone	Longitude	Latitude	Average capacity factor	Max. capacity	Installed capacity (MW)					
						VRELim	REF	VREHigh	HYDry	HYDel	TxNoLim
South Africa	IE	29.8915	-31.0360	0.35	1 140	1 140	1 140	1 140	1 140	1 140	1 140
South Africa	IF	30.0485	-31.2144	0.37	530	530	530	530	530	530	530
South Africa	IW	19.7514	-30.4722	0.37	1 630	1 630	1 630	1 630	1 630	1 630	1 630
South Africa	JB	19.5605	-30.4958	0.36	1 770	1 770	1 770	1 770	1 770	1 770	1 770
South Africa	JL	25.3989	-33.9457	0.38	70	70	70	70	70	70	70
Sudan	CN	36.9478	20.7193	0.37	2 680	-	1 702	2 680	1 702	1 702	1 730
Sudan	CO	36.8701	21.7895	0.41	1 650	1 650	1 650	1 650	1 650	1 650	1 650
Tanzania	AG	35.9528	-7.5613	0.37	1 270	-	1 270	1 270	1 270	1 270	1 270
Tanzania	AH	35.7798	-7.7990	0.38	844	-	844	844	844	844	844
Tanzania	D	35.6799	-6.2817	0.35	78	-	78	78	78	78	78
Tanzania	E	35.5724	-6.0668	0.34	133	-	133	133	133	133	133
Tanzania	O	33.0210	-9.3221	0.35	663	-	663	663	663	663	663
Tanzania	Q	33.2475	-9.0116	0.36	353	-	353	353	353	353	353
Tanzania	R	36.0079	-3.4009	0.34	455	-	-	455	-	-	-
Tanzania	S	36.7936	-3.0776	0.35	137	-	137	137	137	137	137
Tanzania	X	33.4484	-8.3791	0.35	502	-	502	502	502	502	502
Uganda	A	34.9170	2.3774	0.30	82	-	-	82	-	-	-
Uganda	B	34.6612	2.4777	0.34	133	-	-	133	133	-	-
Uganda	C	34.6612	2.4862	0.30	319	-	-	319	-	-	-
Uganda	D	34.7086	2.6552	0.35	458	-	458	458	458	458	458
Uganda	E	34.6656	2.5706	0.33	236	-	-	236	-	-	-
Zambia	E	28.2874	-15.6543	0.32	827	-	827	827	827	827	827
Zambia	G	28.1898	-15.3814	0.32	1 500	-	510	1 500	1 452	336	-
Zambia	O	28.2756	-14.3183	0.29	740	-	-	740	-	-	-
Zimbabwe	AD	32.6004	-18.8997	0.29	165	-	-	165	-	-	-
Zimbabwe	AF	32.7042	-17.9900	0.30	660	-	-	660	-	-	-
Zimbabwe	AR	29.3825	-16.3779	0.34	662	-	662	662	662	662	562
Zimbabwe	AV	31.7014	-16.3295	0.35	814	-	814	814	814	814	814
Zimbabwe	Z	32.6498	-19.1067	0.29	583	-	-	126	-	-	-

7.7 Power Plants

This section presents the lists of existing, committed and candidate power plants included in the analysis. Data of the plants were derived from the EAPP and SAPP master plans (EAPP, 2014; SAPP, 2017), with minor updates to reflect recent developments.

7.7.1 Existing Plants

Country name	Technology type	Tech description
Angola	Diesel	Existing E_Boavista (Eng)/E_Arimba (Eng)/E_Benfica (Luanda) (Eng)/E_Benfica (Huambo) (Eng)
		Existing E_Cazenga (Eng)/E_CFL (Eng)/E_GTG Viana (Eng)/E_Lobito (Eng)
		Existing E_Quileva (Eng)/E_Refineria (Eng)/E_Lubango (Eng)/E_Km 9 (Eng)
	HFO	Existing E_Benguela (Eng)
	Large hydro	Existing E_Cambambe I (H)
		Existing E_Capanda (H)
		Existing E_Chicapa (H)/E_Biopio (H)
		Existing E_Gove (H)
		Existing E_Lomaum (H)
		Existing E_Mabubas (H)
		Existing E_Matala (H)
	Natural gas	Existing E_CIF (G)
Botswana	Coal	Existing E_Morupule B (St)/E_Morupule A (St)
	Diesel	Existing E_Francistown (Eng)
		Existing E_Orapa 1&2 (G)
Burundi	Diesel	Existing Burundi_exi_the
	Large hydro	Existing Burundi_exi_hy/JIJI
DRC	Diesel	Existing E_Bomba (Eng)
		Existing E_Goma (Eng)/E_Gemena (Eng)/E_Buta (Eng)/E_Bandundu (Eng)/E_Boende (Eng)/E_Basankusu (Eng)/E_Bumba (Eng)/E_Butembo (Eng)
		Existing E_Kananga (Eng)/E_Kamina (Eng)/E_Kikwit (Eng)/E_Kabinda (Eng)/E_Kasongo (Eng)/E_Kabalo (Eng)/E_Kasenga (Eng)/E_Inongo (Eng)
		Existing E_Kisangani (Eng)
		Existing E_Lisala (Eng)/E_Libenge (Eng)/E_Lemba (Eng)/E_Lusambo (Eng)/E_Kindu (Eng)/E_Kongolo (Eng)/E_Lukala (Eng)
		Existing E_Mbuji Mayi (Eng)/E_Mbandaka (Eng)/E_Mweka (Eng)/E_Tshela (Eng)/E_Zongo (Eng)
	Large hydro	Existing E_Inga 2 (H)/E_Inga 1 (H)
		Existing E_Nseke (H)/E_Nzilo (H)/E_Mwadingusha (H)/E_Koni (H)
		Existing E_Ruzizi 2 (H)/E_Ruzizi 1 (H)
		Existing E_Soleniama2 (H)/E_Soleniama1 (H)/E_Mobayi (H)/E_Tshopo (H)/E_Piana (H)
		Existing E_Zongo (H)
	Natural gas	Existing E_Muanda (Eng)
	Small hydro	Existing E_Budana (H)/E_Ambwe/Kailo (H)/E_Belia (H)
		Existing E_Kyimbi (H)/E_Kilubi (H)/E_Lutshurukuru (H)/E_Mangembe (H)/E_Lungudi (H)/E_Lulingu (H)
		Existing E_Sanga (H)/E_Mpozo (H)/E_Tshala&Lubilanji1 (H)/E_Moga (H)

Country name	Technology type	Tech description
Djibouti	Diesel	Existing Boulaos/Marabout
Egypt	Diesel	Existing Sharm_el_Sheikh/Hurghada/Karmouz
	HFO	Existing Tebbin
		Existing Walidia/Assiut
	Large hydro	Existing Aswan_1/Aswan_2
		Existing Esna
		Existing High_Aswan_Dam
		Existing Naga_Hamadi
	Natural gas	Existing Abu_Kir/Sidi_Krir_3_4/Sidi_Krir_1_2/Kafr_Dawar/Talkha_210/Damhour_Ext/Damanhour_1/Cairo_West
		Existing Arish
		Existing Ataka/Port_Said_East/Suez_Gulf/Oyoun_Moussa/Abu_Sultan
		Existing Cairo_North/El_Atf/Cairo_South_1/6_October_CC/Cairo_South_2
		Existing DamiettaCC/DamiettaGT/Talkha_750/Damitta_West_Gt/Talkha
		Existing Kuriemat_2
		Existing Kuriemat_3
		Existing Mahmoudia_1/Damanhour_2
		Existing Nubaria_1_2/Sidi_Krir_New
		Existing Nubaria_3/El_Seiuf/Abu_Kir_2
		Existing Port_Said
		Existing Shabab_New_GT/Shabab
		Existing Shouba_El_Kheima/Kuriemat_1/Cairo_West_New/Cairo_West_Ext/Matrouh
		Existing Wadi_Hof/Shouba_GT
	Solar thermal	Existing Kuriemat_solar-thermal
Eswatini	Large hydro	Existing E_Edwaleni 1 (H)
		Existing E_Ezulwini (H)
		Existing E_Maguduza (H)/E_Edwaleni 2 (H)
		Existing E_Maguga (H)
Ethiopia	Diesel	Existing DirDawa/Awash7/Kaliti
	Geothermal	Existing Aluto
	Large hydro	Existing AmartiNeshe
		Existing Awash_2/Awash_3
		Existing Beles
		Existing Finchaa
		Existing Gilgel_Gibe_I
		Existing Gilgel_Gibe_II
		Existing Koka
		Existing Maleka_Wakana
		Existing Sor
		Existing Tekeze_I
		Existing Tis_Abbay_2/Tis_Abbay_1

Country name	Technology type	Tech description
Kenya	Biomass	Existing Mumias
	Diesel	Existing Aggreko_IPP
		Existing Emabakasi
	Geothermal	Existing Eburru
		Existing Olkaria_1
		Existing Olkaria_2/OrPower_4b/OrPower_4a/Olkaria_Well_Head
	HFO	Existing Iberafrica_IPP/Iberafrica_3_IPP
		Existing Kipevu_III_Diesel/Rabai_diesel_IPP/Tsavo_IPP/Kipevu_1_Diesel
	Large hydro	Existing Gitaru
		Existing Kamburu/Masinga
		Existing Kiambere
		Existing Kindaruma
		Existing Sangoro
		Existing Sondu_Miriu
		Existing Tana
		Existing Turkwell
	Small hydro	Existing KY_Small_hydro
Lesotho	Large hydro	Existing E_Muela (H)
Malawi	Diesel	Existing E_Mzuzu Diesel (Eng)
	Large hydro	Existing E_Kapichira Falls Phase I (H)/E_Kapichira Falls Phase II (H)
		Existing E_Nkula Falls B (H)/E_Nkula Falls A (H)
		Existing E_Tedzani Falls III (H)/E_Tedzani Falls I (H)/E_Tedzani Falls II (H)
	Small hydro	Existing E_Wovwe Mini Hydro (H)
Mozambique	Diesel	Existing E_CDM 1/E_Inhambane/E_Tavene
		Existing E_Luis Cabral (G)
		Existing E_Nacala (Eng)
	Large hydro	Existing E_Cahora Bassa (H)
		Existing E_Chicamba (H)
		Existing E_Corumana (H)
		Existing E_Mavuzi 1-3 (H)/E_Mavuzi 4-5 (H)
	Natural gas	Existing E_Aggrekko (Eng)
		Existing E_Ressano Garcia EDM/Sasol (Eng)/E_Ressano Garcia Gigawatt/E_Beloluane (G)
		Existing E_Temane 2 (Eng)/E_Temane (Eng)
Namibia	Coal	Existing E_Van Eck (St)
	Diesel	Existing E_Anixas (Eng)
	HFO	Existing E_Paratus (Eng)
	Large hydro	Existing E_Ruacana (H)
Tanzania	Biomass	Existing E_TPC (Bio)/E_TANWAT (Bio)
	HFO	Existing E_Tegeta IPTL (Eng)/E_Nyakato (Eng)
	Large hydro	Existing E_Kidatu (H)
		Existing E_Kihansi (H)
		Existing E_Mtera (H)/E_Pangani Falls (H)
		Existing E_Nyumba Ya Mungu (H)/E_Hale (H)
	Natural gas	Existing E_Kinyerezi (G)
		Existing E_Songas I (G)/E_Songas III (G)
		Existing E_Songas II (G)
		Existing E_Symbion (Ubungo) (G)
		Existing E_Tegeta (Eng)
		Existing E_Ubungo II (G)/E_Ubungo I (G)
	Small hydro	Existing E_EA Power (H)/E_Mapembasi (H)/E_Mwenga (H)

Country name	Technology type	Tech description
Rwanda	Diesel	Existing Gikondo/Jabana1
		Existing Mukungwa
	HFO	Existing Jabana2
	Large hydro	Existing Rwanda_Exi_Hy
	Natural gas	Existing KP1_Gisenyi_Methan
South Africa	Biomass	Existing E_REIPPPP3-Johannesburg Landfill Gas (St)
		Existing E_REIPPPP4-Ngodwana Energy Project (St)/E_REIPPPP3-Mkuze Biomass (St)
	Coal	Existing E_Arnot (St)
		Existing E_Athlone (St)
		Existing E_Camden (St)
		Existing E_Duvha (St)
		Existing E_Grootvlei (St)
		Existing E_Hendrina (St)
		Existing E_Kelvin B (St)/E_Rooiwal (St)/E_Kelvin A (St)/E_Pretoria West (St)/E_Secunda (Sasol Chemical) (St)
		Existing E_Kendal (St)
		Existing E_Komati I (St)/E_Komati II (St)
		Existing E_Kriel (St)
		Existing E_Lethabo (St)
		Existing E_Majuba II (St)/E_Majuba I (St)
		Existing E_Matimba (St)
		Existing E_Matla (St)
		Existing E_Tutuka (St)
	Diesel	Existing E_Ankerlig OCGT (Atlantis) (G)/E_Acacia (G)
		Existing E_Avon (G)
		Existing E_Gourikwa OCGT (Mossel Bay) (G)/E_Dedisa (G)/E_Port Rex Gas (G)
	Large hydro	Existing E_Gariep (H)/E_Vanderkloof (H)/E_Collywobbles (H)/E_Ncora (H)
	Natural gas	Existing E_Sasolburg (Eng)
		Existing E_Secunda (Sasol Synthetic Fuels) (G)
	Nuclear	Existing Koeberg
	Pump storage	Existing Pump Storage (Turbine)
	Pumping	Existing Pump Storage (Pump)
	Small hydro	Existing E_Neusberg HEP (H)/E_Kruisvallei Hydro (H)/E_Stortemelk Hydro (H)
	Solar thermal	Existing E_REIPPPP1-KaXu Solar CSP (CSP)/E_REIPPPP3-Karoshoek CSP (CSP)/E_REIPPPP3-Xina CSP (CSP)/P_SA_CSP
		Existing E_REIPPPP1-Khi Solar One CSP (CSP)/E_REIPPPP2-Bokpoort CSP (CSP)
South Sudan	Diesel	Existing South_Sudan_Exi_The
Sudan	Coal	Existing GarriST_4
	Diesel	Existing Dr_Sherif_GT
		Existing GarriCC_1/GarriCC_2
	HFO	Existing Dr_Sherif_3/Dr_Sherif_2/Dr_Sherif_1
	Large hydro	Existing Jebel_Aulia
		Existing Merowe
		Existing Roseires
		Existing Sennar
	Small hydro	Existing Kashm_El_Girba

Country name	Technology type	Tech description
Uganda	Biomass	Existing Kakira
		Existing Kinyara
	HFO	Existing Electromaxx
		Existing Namanve
	Large hydro	Existing Bujagali
		Existing Kira
		Existing UG_Small_hydro
Zambia	Coal	Existing E_Maamba Coal I (St)
	Large hydro	Existing E_Ithezi Thezi (H)
		Existing E_Kafue Gorge (H)
		Existing E_Kariba NB (H)/E_Kariba NBE (H)
		Existing E_Lusiwasi Upper (H)/E_Lusiwasi (H)/E_Mulungushi (H)
		Existing E_Victoria Falls (H)
	Small hydro	Existing E_Chishimba Falls (H)/E_Lunzua (H)
		Existing E_Musonda Falls (H)
Zimbabwe	Coal	Existing E_Bulawayo (St)
		Existing E_Harare 3 (St)/E_Harare 2 (St)
		Existing E_Hwange I (St)/E_Hwange II (St)
		Existing E_Munyati (St)
	Diesel	Existing E_Dema Emergency
	Large hydro	Existing E_Kariba South 1 (H)

7.7.2 Committed Plants

Country name	Technology type	Tech description	First year
Angola	Large hydro	Committed P_Angola_Cacula Cabasa (H)	2022
		Committed P_Angola_Camambe II (H)	2017
		Committed P_Angola_Lauca (H)/P_Angola_Lauca_Ecologica (H)	2017
	Natural gas	Committed P_Angola_Soyo I (G)	2017
Botswana	Coal	Committed P_Botswana_Morupule B 5&6	2025
	Solar PV - utility	Committed P_Botswana Solar (PV)	2031
Burundi	Large hydro	Committed Kabu_16/Kabu 23	2018
		Committed Mpanda	2018
		Committed Mulembwe	2019
		Committed RUSUMO_FALLS	2018
DRC	Large hydro	Committed P_DRC_Ruzizi 3 (H)	2023
		Committed P_DRC_Zongo 2 (H)	2017
Djibouti	Geothermal	Committed DBGeothermal	2020
	HFO	Committed Jaban	2018
Egypt	Coal	Committed EG-ST-SUBCRI_20	2020
	HFO	Committed Assuit_New	2018
	Natural gas	Committed Abu_Kir_NewST	2015
		Committed Ain_SokhnaST/SuezST	2015
		Committed Damitta_West_Gt_New	2017
		Committed EG-CCGT_20	2016
		Committed El_ShababCC	2017
		Committed Giza_NorthCC/BanhaCC/6_October_CC_New/Giza_NorthCC_2	2015
		Committed HelwanSouthST	2018
	Nuclear	Committed EG_Nuclear	2025
	Pump storage	Committed Ataqa Pump Storage (Turbine)	2024
	Pumping	Committed Ataqa Pump Storage (Pump)	2024
	Small hydro	Committed MiniHydro	2015
	Solar thermal	Committed Solar-thermal	2021
Eswatini	Large hydro	Committed P_Lower Maguduza (H)	2018
Ethiopia	Biomass	Committed Bamza-120/Beles1/Beles2/Beles3/Reppi-EFW-50/Kessem/Wenji	2015
		Committed FinchaaBagasde	2015
		Committed Melkasedi-137/OmoKuraz1	2020
		Committed OmoKuraz2/OmoKuraz3/OmoKuraz4/OmoKuraz5/OmoKuraz6	2020
		Committed TendaueEnde	2015
		Committed Wolkayit	2016
	Geothermal	Committed AlutoLangano	2020
	Large hydro	Committed Genale3	2020
		Committed Gilgel_Gibe_III	2016
		Committed Renaissance	2019

Country name	Technology type	Tech description	First year
Kenya	Biomass	Committed Kwala	2021
	Coal	Committed KY_Coal/KY_Coal2	2016
	Geothermal	Committed Baringo	2017
		Committed Menengai_2/AGIL/OLK_V/OLK_VI/OLK1B/OLK1B_3/OLK4/ Menengai_I/OLK1B_2/MENW	2015
		Committed OLKWH1	2015
		Committed OLKWH2	2015
		Committed ORP4	2020
		Committed Silali	2020
		Committed Suswa/Suswa2/Eburru_New	2020
	HFO	Committed Triumph/GULF/THIKA	2015
	Large hydro	Committed Kindaruma_opt	2015
	Natural gas	Committed Kipevu_GT_I_III/Rabai_NG/Tsavo_NG	2017
		Committed KY_LNG	2017
Lesotho	Pump storage	Committed Kobong Pump Storage (Turbine)	2025
	Pumping	Committed Pump Storage (Pump)	2025
Malawi	Coal	Committed P_Malawi_Kammawamba (Coal)	2019
	Large hydro	Committed P_Malawi_Tedzani Falls IV (H)	2019
Mozambique	Coal	Committed P_Moz_N_Tete	2023
	Diesel	Committed P_Moz_N_Nacala JICA	2019
	Large hydro	Committed P_Moz_N_Moamba Major (H)	2024
		Committed P_Moz_N_Mphanda Nkuwa (H)	2025
	Natural gas	Committed C_Kuvaninga (G)	2017
		Committed P_CTM JICA 1 (G)/P_CTM JICA 2 (G)	2019
		Committed P_Moz_S_MGTP EDM_Sasol (G)	2022
Namibia	Large hydro	Committed P_Namibia_Baynes (H)	2026
	Solar PV - utility	Committed P_Namibia_Solar	2017
	Wind	Committed P_Namibia_Wind	2021
Tanzania	Coal	Committed P_Tanzania_Coastal (Coal)	2019
		Committed P_Tanzania_Kiwira I (Coal)/P_Tanzania_Kiwira II (Coal)	2018
		Committed P_Tanzania_Mchuchuma II (Coal)/P_Tanzania_Mchuchuma I (Coal)	2020
		Committed P_Tanzania_Ngaka I (Coal)	2019
		Committed P_Tanzania_Ngaka II (Coal)	2021
	Large hydro	Committed P_Tanzania_Ikondo (H)	2029
		Committed P_Tanzania_IringaNginayo (H)/P_Tanzania_Iringalbosa (H)	2026
		Committed P_Tanzania_Kakono (H)	2022
		Committed P_Tanzania_Kikonge (H)	2034
		Committed P_Tanzania_Malagaresi (H)	2022
		Committed P_Tanzania_Rusumo (H)	2020
		Committed P_Tanzania_Steiglers Gorge II (H)/P_Tanzania_Steiglers Gorge I (H)	2021
	Natural gas	Committed P_Tanzania_Kinyerezi IV CCGT (NG)/P_Tanzania_Kinyerezi III CCGT (NG)/P_Tanzania_Kinyerezi II CCGT (NG)/P_Tanzania_Kinyerezi I OCGT (NG)	2022
		Committed P_Tanzania_Mtwara OCGT (NG)	2020
		Committed P_Tanzania_Somanga CCGT (NG)	2021

Country name	Technology type	Tech description	First year
Rwanda	Coal	Committed Akanyaru_Peat	2020
		Committed Gishoma_Peat	2015
		Committed HakanPeat	2017
	Diesel	Committed RW_Diesel	2015
	Large hydro	Committed Rusumo_RW	2019
	Natural gas	Committed Gisenyi_Methane	2018
		Committed KivuWattGT_2/KivuWattGT_1	2015
		Committed KSEZ_LNG	2017
South Africa	Coal	Committed E_Kusile (St)	2017
		Committed E_Medupi (St)	2015
	Pump storage	Committed Ingula Pump Storage	2017
	Pumping	Committed New Pump Storage (Pump)	2017
South Sudan	Large hydro	Committed FulaSmall	2017
Sudan	Coal	Committed RedSea	2017
	HFO	Committed AlFula	2016
		Committed Kosti	2015
	Large hydro	Committed UpperAtbara	2016
	Natural gas	Committed Port Sudan CCGT	2017
Uganda	Biomass	Committed Kinyara2/Sugar_Allied_Industries	2015
	Coal	Committed Kabale_Peat	2016
	Geothermal	Committed Katwe1	2027
	HFO	Committed Albatros	2021
	Large hydro	Committed Ayago	2022
		Committed Isimba	2020
		Committed Karuma_High	2020
		Committed UG_Shydro_com	2020
Zambia	Coal	Committed P_Zambia_Maamba Coal II	2022
	Large hydro	Committed E_Lusiwasi Lower (H)	2021
		Committed P_Zambia_Batoka Gorge North (H)	2023
		Committed P_Zambia_Kafue Gorge Lower (H)	2021
		Committed P_Zambia_Kalungwishi I (H)	2018
		Committed P_Zambia_Lusiwasi Extension (H)	2018
Zimbabwe	Coal	Committed P_Zimbabwe_Hwange Ext (Coal)	2022
	Large hydro	Committed P_Zimbabwe_Batoka Gorge South (H)	2023
		Committed P_Zimbabwe_Gairezi (H)	2021
		Committed P_Zimbabwe_Kariba South Ext (H)	2018

7.7.3 Candidate plants

Country name	Technology type	Tech description	First year
Angola	Large hydro	Candidate P_Angola_Tumuludo Casador (H)	2028
Burundi	Large hydro	Candidate RUZIZI_4/RUZIZI_3	2017
DRC	Large hydro	Candidate P_DRC_Inga 4 (H)/P_DRC_Inga 3 BC (H)/P_DRC_Inga 3 HC (H)	2027
Eswatini	Biomass	Candidate P_Eswatini_Biomass	2028
Ethiopia	Geothermal	Candidate ET_GEO	2021
	Large hydro	Candidate BekoAbo	2028
		Candidate Genale6D/Genale5	2021
		Candidate GibeIV/GibeV	2023
		Candidate HaleleWerabessa/Geba1_2/ChemogaYeda1_2/AleltuWest/Genji/AleltuEast/Gojeb	2023
		Candidate Karadobi	2029
		Candidate LowerDedessa	2032
		Candidate UpperDabus	2021
		Candidate UpperMandaya	2030
Malawi	Biomass	Candidate P_Malawi_Biomass	2020
	Diesel	Candidate P_Malawi_Engines Diesel (medium)	2022
	HFO	Candidate P_Malawi_HFO	2019
	Large hydro	Candidate P_Malawi_Kapichira III (H)	2022
		Candidate P_Malawi_Kholombizo (H)	2018
		Candidate P_Malawi_Mpatamanga (H)	2023
Mozambique	Coal	Candidate P_Moz_N_ENRC	2026
	Large hydro	Candidate P_Moz_N_Tsate (H)	2027
Tanzania	Large hydro	Candidate P_Tanzania_Songwe Bipungu (H)/P_Tanzania_Songwe Manolo (H)/P_Tanzania_Songwe Sofre (H)	2038
Rwanda	Large hydro	Candidate Nyabarongo1/Nyabarongo2	2015
South Africa	Biomass	Candidate P_SA_Biomass	2027
	Coal	Candidate P_SA_Coal (medium)/P_SA_Coal (large)	2022
	Natural gas	Candidate P_SA_CCGT NG	2029
		Candidate P_SA_OCGT NG	2029
South Sudan	Large hydro	Candidate Fula	2024
		Candidate Lakki	2024
Sudan	Large hydro	Candidate Dal/Shereik	2020
		Candidate Kajbar	2024
		Candidate Mograt	2030
Zimbabwe	Biomass	Candidate P_Zimbabwe_Chisumbanje biomass	2028

7.8 Candidate interconnectors

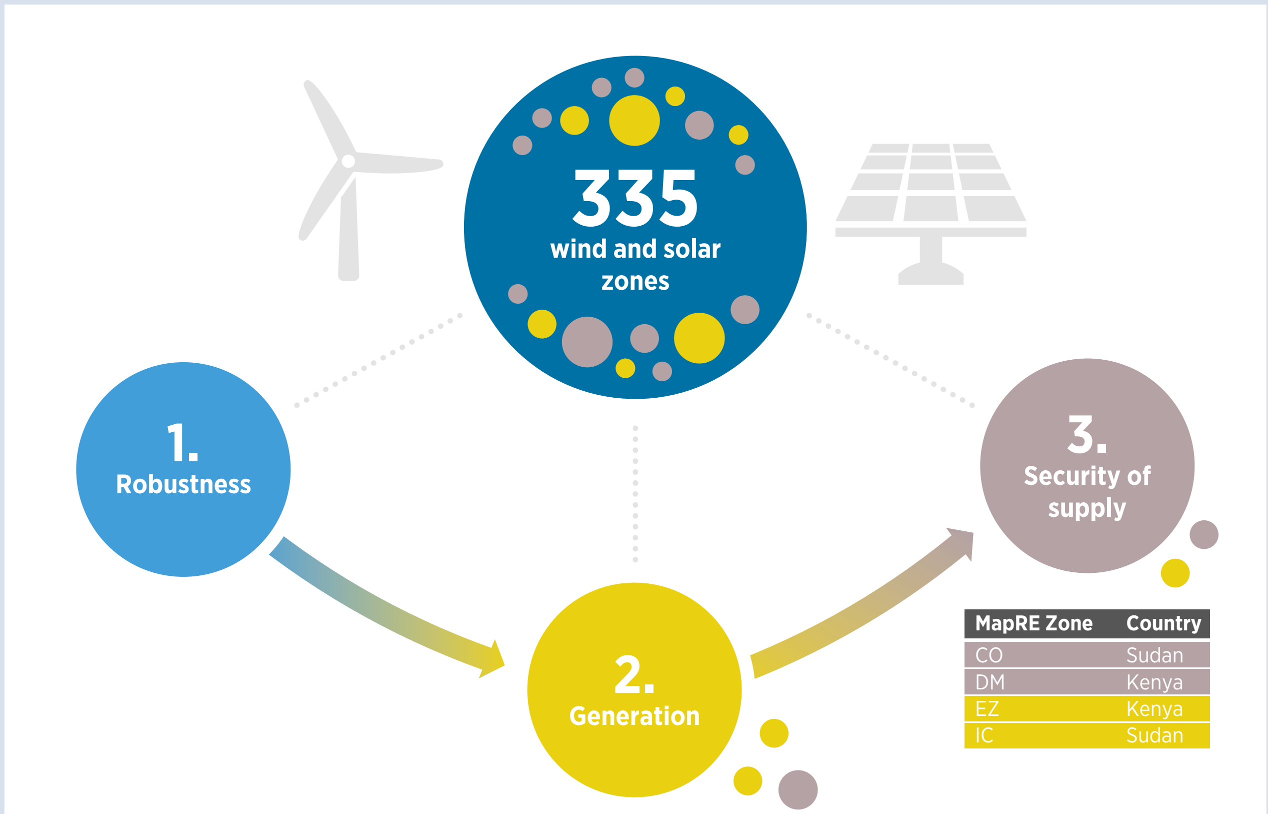
Interconnector	Capacity (MW)	Cost (USD million)	Unit cost (USD/MW)	Source
Candidate DRC–South Africa Grand Inga HVDC Phase 1 (Inga - Merensky) 600HVDC	2 500	4 737.5	1 895	**EDF AECOM presentation volume 1**
Candidate DRC–Burundi (?–Bujumbura) 400AC	748	41	55	**Aurecon**
Candidate DRC–Rwanda (Poids–Bukari) 220AC	388	89	229	
Candidate DRC–Rwanda (Kamanyola–Rusizi) 400AC	600	89	148	
Candidate DRC–Uganda 400AC	388	89	229	
Candidate Egypt–Sudan (Isiah–Dongola) 500DC	1 732	444	256	
Candidate Ethiopia–Dijbouti (Dire Dawa–Border) 400AC	200	98	490	**EAPP master plan**
Candidate Rwanda–Tanzania (Gasogi–Rusumo) 220AC	181	47	260	**Aurecon**
Candidate Sudan–Ethiopia (Ed Damazin–Beles) 500AC	2 321	267	115	
Candidate Sudan–South Sudan (?–Bobanosa) 220AC	120	267	2 225	
Candidate Sudan–Uganda	250	93	371	
Candidate Tanzania–Burundi (Kigoma–Musimba) 400AC	1 109	44	40	
Candidate Zambia–Zimbabwe (Livingstone–Zambezi) 330AC	500	109	217	
Candidate DRC–Zambia (Matadi/Kolwezi–Lumwana/Solwezi) 500DC	2 000	1 510	755	
Candidate Inga N`Zeto Phase 1 DRC–Angola (Matadi–Nzeto) 400AC	1 663	76	46	
Candidate Mozambique–Malawi Inteconnector (Matambo–Phombeya) 400 kV AC	1 800	253	110	
Candidate Mozambique–Tanzania Interconnector 400AC	300	253	371	
Candidate Zambia–Mozambique () 400AC	300	20	371	
Candidate Mozisa Mozambique–Zimbabwe (Songo–Msoro) 400AC	2 300	61	27	
Candidate Namibia–Botswana (Gerus–Maun) 400AC	300	289	963	
Candidate Rwanda–Burundi (Ruzuzi–Bujumbura) 220AC	610	55	90	
Candidate Zimbabwe–South Africa (Insukamini–Nzehelele) 400AC	1 725	112	65	

7.9 Project-specific analysis – zone ranking process

As shown in the schematic in Figure 4-1 (p. 49), nine top-performing solar PV and wind projects were selected for discussion in this report, post-modelling, from 335 zones. As the SPLAT model holistically considers costs, resource quality, flexibility, trade and other dynamic interactions within the system, the viability of the zones under these system considerations are automatically factored into the modelling results. If maximum capacity limits had not been imposed, the zones with the highest production are those that are the least costly to build and dispatch from the system's perspective. However, because the buildout of each zone is constrained by its maximum capacity, a zone cannot build more than its build limit, even if it is more cost effective than another zone with a higher maximum capacity constraint. Therefore, factors in addition to the zones' capacities are considered when selecting the generation capacity projects for consideration under PIDA PAP II.

Figure 7-1 illustrates the attributes and process used to identify a total of nine suggested generation capacity projects out of the 335 solar PV and wind zones modelled. The number nine is only illustrative, to give a manageable number of suggestions. The nine projects form a small share of total demand in the ACEC – they are chosen for their attributes which are demonstrative of high-quality resource potential.

Figure 7-1: Attributes and process for identifying nine suitable generation projects

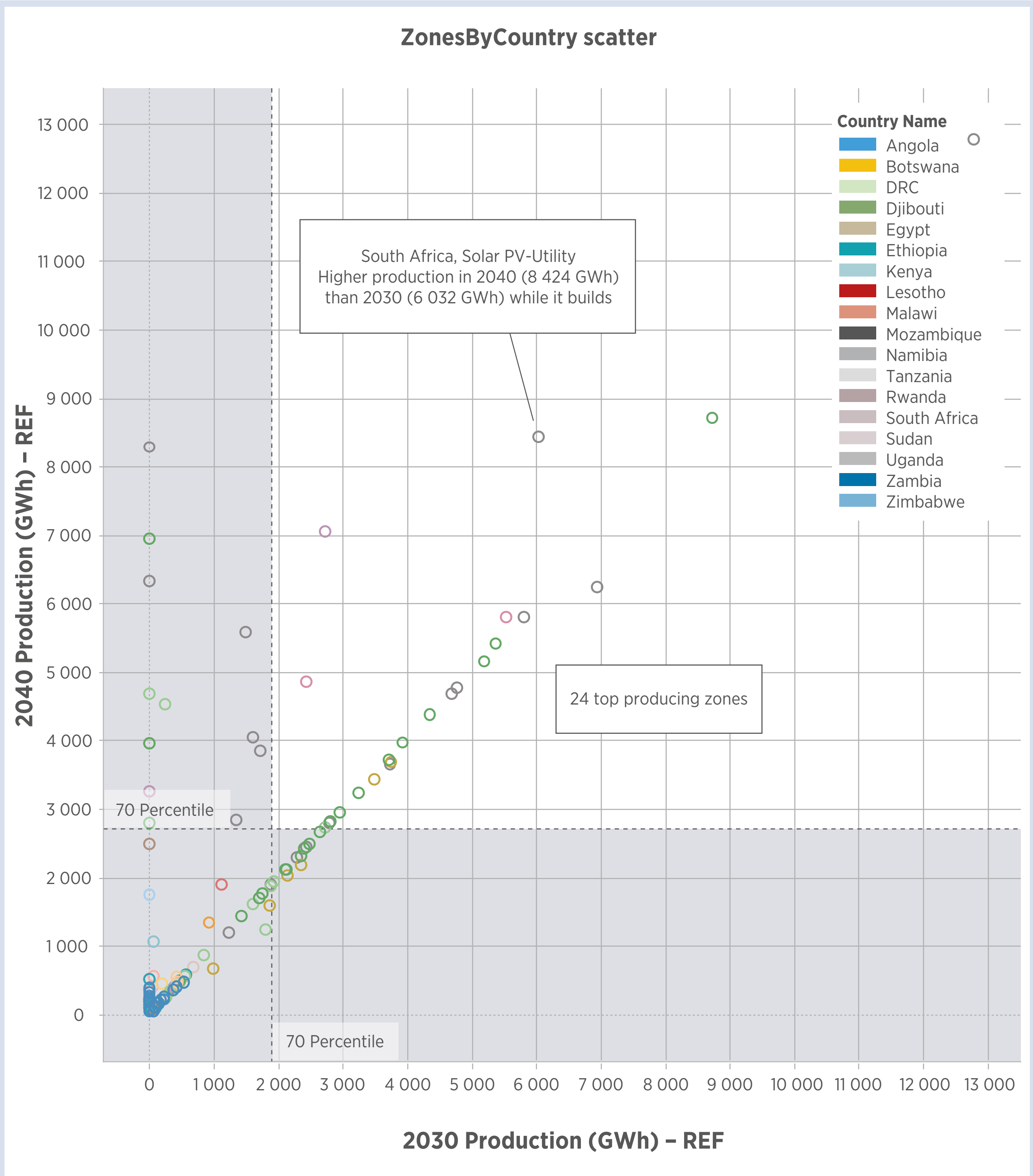


MapRE Zone	Country
AR	South Africa
AO	South Africa
V	South Africa
FY	Egypt
GU	South Africa

MapRE Zone	Country
CO	Sudan
DM	Kenya
EZ	Kenya
IC	Sudan

To ensure the selection is robust, the zones are first filtered to only include 115 zones that produce across all six scenarios in 2040 in the model. Figure 7-2 shows the zones with their production (in GWh) in 2030 and 2040 in the Reference scenario on a scatter plot, and the reference lines on both axes showing the 70th percentile. The x- and y-axes of the plot represent the generation of a zone in 2030 and 2040, respectively. There are 24 zones that produce within the highest 30th percentile in both 2030 and 2040 under the Reference scenario.

Figure 7-2: Scatter plot of production (GWh) by zones in 2040 (y-axis) and 2030 (x-axis)



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