# CHARLES UNIVERSITY IN PRAGUE

## FACULTY OF SOCIAL SCIENCES

### Institute of Economic Studies

**DISSERATION**

# Three Essays in Development Economics

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Academic year: **2020/2021**

# Declaration of Authorship

The author hereby declares that she compiled this thesis independently; using only the listed resources and literature, and the thesis has not been used to obtain a different or the same degree.

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Prague, February 25, 2021

Author’s signature

## Acknowledgements

First of all, I would like to thank my co-authors prof. Roman Horváth Ph.D., doc. PhDr. Tomáš Havránek Ph.D. for their valuable research contribution to the first paper entitled *Financial Development and Economic Growth: A Meta-Analysis,* and M.A. Nicholas Elms, my co-author and colleague, for his vital contribution to the second and third research papers entitled "*The Costs of Providing Access to Electricity in Selected Countries in Sub-Saharan Africa and Policy Implications*" and "*Potential gains from regional integration to reduce costs of electricity supply and access in Southern Africa*".

Secondly, my thanks goes to my advisor doc. Ing. Tomáš Cahlík CSc. who has shown patience with me when I was juggling my studies and full-time work at Frontier Economics and later at the World Bank in the Energy and Infrastructure Department in the West African region.

Thirdly, my thank you goes to all the members of the dissertation committee, who embarked on this journey in the final months of writing my thesis and proposed valuable comments, some of which were not only incorporated in this thesis but also in the respective journals where my later papers were either published or submitted for publication.

Lastly, I would like to thank all those who have been part of this journey, most importantly my family and friends.

This work was supported by the Charles University Grant Agency (grant number 829 317). This work is also part of a project that has received funding from the European Union's Horizon 2020 research and innovation programme under the Marie Skłodowska-Curie grant agreement No. 681 228. I also benefited from a secondment to U.C. Berkeley supported under GEMCLIME mobility grant.

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Valíčková, P., 2021. Three Essays in Development Economics. Dissertation Thesis. Charles University, Faculty of Social Sciences, Institute of Economic Studies, Prague, 235 pages. Advisor: doc. Ing. Tomáš Cahlík CSc.

# Abstract

This dissertation thesis touches on some important aspects of development, including financial development and improved access to reliable energy sources, regional integration and expanded opportunities for trade. This thesis was written to help guide policy reforms especially in developing countries to expand sources of growth and put countries on track to better meet their long-term development goals, including a better and more sustainable future for everyone. This dissertation consists of three papers.

In the first paper I investigate the empirical evidence on the relationship between financial development and economic growth. In doing so, I assessed over 270 studies for their potential inclusion in a meta-analysis. From those studies that contained an empirical estimate of the finance growth relationship, I compiled 1,334 coefficients and coded study characteristics for each. Taking the reported estimates together, I find a positive link between financial development and economic growth, but with widely varying individual estimates. By applying a multi-variate meta-regression, I explain the variation in reported results, stemming not only from differences in research design (by authors addressing or ignoring potential endogeneity issues) but also from real drivers (different regional and time effects).

In the second paper, I estimate the costs of scaling up access to electricity through the main grid. I do so in view of the limited access to modern electricity services among countries in Sub-Saharan Africa, despite its widely recognised importance for human and economic development. Specifically, I estimate the incremental costs of scaling up electricity access in the Southern African Power Pool. I do so by developing and applying a least-cost power system generation despatch and investment model for the region. My analysis shows that at the current rate of progress in providing households with access, less than 60% of the population in SAPP will have access to electricity by 2030. Yet, the incremental costs of providing access are relatively low when compared to the overall forward-looking system generation cost of serving the current households and the non-residential sectors of the economy. In fact, the resulting cost is below of what a typical household pays for poor alternatives to electricity, such as kerosene for lighting, implying that policy makers should accelerate the rate at which electricity access is provided.

The lack of access to modern electricity services in Sub-Saharan Africa is often linked to affordability issues. With this in mind, in the third paper I look at how certain policy actions could reduce the cost of providing electricity access, and therefore help to shift towards more sustainable sources of energy in the region. Specifically, I look at how increased power trade and electricity interconnection among countries in SAPP could reduce the underlying cost of generation and hence the costs of supply. I find that the existing interconnection capacity in the SAPP region is not utilised efficiently and that countries are foregoing some benefits of power trade in the short term and benefits of taking a regional approach to power system planning. Utilising the existing interconnector capacity efficiently and building and using new interconnectors when economically beneficial to do so reduces forward looking costs of generation and transmission interconnector investments by almost 6% compared to no trade. The lower cost helps to reduce the affordability constraint related to electricity access, with access to reliable energy being one of the key drivers of human and economic development. I also find that trade can significantly contribute towards meeting other policy objectives, such as reducing greenhouse gas emissions. With trade, less coal fired generation is required, particularly in South Africa and Zimbabwe, and more hydro and solar photovoltaics renewable generation capacity is developed elsewhere in the region.

**JEL Classification**: C83, G10, O40, Q41, Q47, I3, L94, O55, O20, O55, Q47.

**Keywords**: Financial development, economic growth, meta-analysis, electricity access, power sector modelling, Sub-Saharan Africa, benefits of trade

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## Acronyms

BAU – Bayesian model averaging

CAGR - compounded annual growth rate

CAPEX – capital expenditure

CAPP - Central African Power Pool

CAR – Central African Republic

CCGT - closed cycle gas turbine

$CO_2$ – carbon dioxide

$CO_2e$ - carbon dioxide equivalent

COVID-19 - Corona Virus Disease 2019

CSP - concentrated solar power

DRC - Democratic Republic of Congo

EAPP - Eastern African Power Pool

EC – European Commission

FD – financial development

FDC - financing during construction

FE – fixed-effects

GAMS - General Algebraic Modelling System

GDP – gross domestic product

GFDD – Global Financial Development Database

GMM – generalised methods of moments

GMT - Greenwich Mean Time

HCB - Hidroeléctrica de Cahora Bassa

HFO - heavy fuel oil

HHI - Herfindahl-Hirschman index

HVDC – high voltage direct current

IAEA - International Atomic Energy Agency

IC - interconnector

ICE - internal combustion engine

IEA – International Energy Agency

IPP – independent power producer

IRENA - International Renewable Energy Agency

IRP – Integrated Resource Plan

IV – instrumental variable

LCOE - levelized cost of electricity

LEAP – Long-range Energy Alternatives Planning

LHV - low heating value

LNG - liquefied natural gas

LoL – loss of load

MAER-Net - Meta-Analysis of Economics Research Network

MDG – Millennium Development Goals

MESSAGE – Model for Energy Supply Strategy Alternatives and their General Environmental Impact

MRA – multivariate meta-regression

OCGT - open cycle gas turbine

OECD – Organisation for Economic Co-operation and Development

OLS – ordinary least squares

O&M - operations and maintenance

OSeMOSYS – The Open Source Energy Modelling System

PHS – pumped hydro storage

PJM - Pennsylvania Jersey Maryland

PV – solar photovoltaics

RE – random effects

ROR – run of river

SA - South Africa

SADC – Southern African Development Community

SAPP - Southern African Power Pool

SDGs - Sustainable Development Goals

SE4ALL - Sustainable Energy for All

SPLAT – The System Planning Tool

SSA - Sub-Saharan Africa

ST - steam turbine

SWI – Shannon-Wiener Index

th – thermal

T&D - transmission and distribution

TEMBA – The Electricity Model Base for Africa

TIAM – The TIMES Integrated Assessment Model

TIMES - The Integrated MARKAL-EFOM System

UN – United Nations

VoLL – value of lost load

VRE – variable renewable energy

WAPP - West African Power Pool

WACC – weighted average cost of capital

WDI – World Development Indicators

WTP – willingness to pay

# Chapter 1

# General Introduction

A growing body of research shows that financial institutions (such as banks and insurance companies) and financial markets can play an important role in contributing towards economic development and poverty alleviation (Levine, 1997; Levine, 2005). Finance matters for the wellbeing of individuals, which goes beyond overall economic growth (OECD and Word Bank, 2006). Having access to financial services can help individuals invest in their future such as investing in education or saving for retirement, engage in entrepreneurial activities, better manage risk, and smooth their income and hence deal with hardships and shocks affecting their daily income (Demirgüç-Kunt et al., 2018; OECD and World Bank, 2006). Access to these services also benefits society by enabling a more inclusive growth path (Stein, 2013). Similarly, access to reliable energy is recognised as a key driver of human and economic development (IEA, 2010; SE4ALL, 2017; UN, 2017) and a necessary condition for eradicating poverty and embarking on a path of inclusive economic growth (IEA, 2010; UN, 2017; Sarkodie and Adams, 2020). For example, access to modern lighting increases the useful hours of the day, enhances people's health, safety, financial inclusion and economic activity (Bhatia and Angelou, 2015).

Financial development, access to financial services, and access to reliable energy can therefore be seen as important means towards development ends and have been studied extensively in the empirical growth literature. Given their importance, access to financial services and access to modern energy also have their place in the 2030 Agenda for Sustainable Development, which consists of 17 Sustainable Development Goals (SDGs) adopted by the United Nations in 2015.

Specifically, SDG 7 aims at ensuring access to affordable, reliable and sustainable energy services for all.[1] While financial development and financial inclusion[2] are not an explicit SDG, they have been recognised as enablers of many other SDGs and included as specific targets in eight of the 17 development goals. These include, among others, SDG 1 on eradicating poverty, SDG 2 on ending hunger and promoting food security, SDG 3 on promoting good health and well-being, SDG 5 on enhancing gender equality and economic empowerment of women, SDG 8 on promoting inclusive and sustainable economic growth, and SDG 10 on reducing inequalities and ensuring no one is left behind (Klapper et al., 2016; UN, 2020).

Similarly, access to reliable and affordable energy is often seen as vital for achieving other development goals. These include improvements in health (SDG 3), education (SDG 4), gender equality (SDG 5), provision of water for agriculture and drinking (SDG 6), all of which contribute towards the overarching objective of poverty eradication (SDG 1) (OECD/IEA, 2017; McCollum et al., 2018). Access to modern energy services can also help with climate change mitigation efforts (SDG 13).

While important steps have been made towards eradicating the electricity access gap and improving access to formal financial services, with the latter also leading to improved indicators of financial development, progress has, however, been uneven. Today, Sub-Saharan Africa (SSA) remains the region where most of those without access to these basic services live, and where indicators of financial development lag those in the rest of the world. Furthermore, access to formal banking systems and financial markets, and access to modern energy services are often reserved for those who are already better off (OECD and World Bank, 2006).

According to the most recent data contained in the Global Financial Inclusion database, only 43% of adults (15 years and older) have some form of money account[3] in SSA compared to around 95% in the Eurozone, 94% in North America, and 69%

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[1] While access to affordable, reliable and modern energy services encompasses both the share of the population with access to electricity (SDG 7.1.1) and the share of the population that relies on clean fuels and technologies for cooking (SDG 7.1.2), my research is concerned entirely with the former.

[2] Financial inclusion and financial development are distinct but related concepts. For example, the Global Financial Development Database is an extensive dataset that includes over 100 different indicators and measures of the a) size of financial institutions and markets, b) degree to which individuals have access to financial services, c) efficiency of financial intermediaries and markets in channelling resources and facilitating financial transactions, and d) stability of financial institutions and markets (Cihak et al., 2012). These indicators are then used by practitioners as proxies for financial development with researchers having relied historically predominantly on measures of financial depth (Valickova et al., 2015).

[3] A money account is either an account with a bank or other financial institution or a mobile money account provided by a mobile network operator. Mobile money accounts offer ways to make direct payments, and thus offer an alternative to traditional debit or credit cards and do not need to be linked to an account at a financial institution. The proportion of adults (15 years and older) that have an account at a bank or other financial institution or with a mobile money-service provider is indicator number 8.10.1 in the SDGs monitored under target 8.10 (strengthening the capacity of domestic financial institutions to encourage and expand access to banking, insurance and financial services for all).

globally. Furthermore, when looking at accounts with a bank or other financial institution, access in SSA is even more limited with only 33% of the population aged 15+ having such an account. Given the limited access to formal financial services, accessing emergency funds when needed is not possible for over 53% of the population (aged 25+) in SSA. Furthermore, people must rely more often on informal channels such as family and friends and rely on cash, which can be more difficult to manage, unsafe, make saving more difficult, and significantly add to transaction costs (Demirgüç-Kunt et al., 2018). Given the limited access to formal financial services, indicators of overall financial development, such as financial depth or stock market capitalisation, remain very low in SSA compared to the rest of the world.

Similarly, while important steps have been made towards eradicating the electricity access gap, about two thirds of the global population without access to electricity today live in SSA. In SSA, less than half of the population has access to electricity[4] (IEA, 2020). Furthermore, many of those with access face reliability issues (Blimpo and Cosgrove-Davies, 2019), affecting their ability to get electricity when needed. Those without reliable access must rely on poor quality and polluting energy sources such as solid fuels, kerosene and candles to meet their basic energy needs, sources that are associated with numerous problems and are detrimental to the environment and to the health of those people (Kimemia et al, 2014; IFC, 2012). Moreover, these poor alternatives to electricity supply are often more expensive (Schnitzer et al., 2014), reducing the disposable income of households that could instead be used in income generating activities.

A brief regional summary of selected measures of financial development, including financial inclusion metrics monitored under target 8.10, and the share of population with electricity access monitored under target 7.1.1 of the SDGs is provided in **Table 1**.

[4] The proportion of the population with access to electricity is indicator number 7.1.1 in the SDGs monitored under target 7.1 (ensuring universal access to affordable, reliable and modern energy services by 2030).

**Table 1: Financial development and inclusion and electricity access by region**

| Region | SSA | Eurozone | North America | World |
|---|---|---|---|---|
| Financial institution account (% age 15+) | 33% | 95% | 94% | 67% |
| Mobile money account (% age 15+) | 21% | n/a | n/a | 4% |
| **Adults with an account (% age 15+)** | **43%** | **95%** | **94%** | **69%** |
| Accessing emergency funds not possible (% age 25+) | 53% | 21% | 24% | 41% |
| Main source of emergency funds: family and friends (% age 25+) | 28% | 17% | 7% | 24% |
| **Financial depth to GDP (%)** | **30%** | **94%** | **96%** | **58%** |
| **Stock market capitalisation to GDP (%)** | **32%** | **55%** | **143%** | **78%** |
| **Electrification rate (% of population)** | **45%** | **>99%** | **>99%** | **89%** |

*Source: Author based on GFDD (2019), Demirgüç-Kunt et al. (2018) and IEA (2019).*
*Note: Data on electrification rates are for the year 2018. Data on financial inclusion come from the Global Findex database and are for 2017. In both cases these are the most recent data available at the time of writing this thesis. Data on mobile money accounts were not available for Eurozone and North America. 'Financial depth' is measured as liquid liabilities of the financial system to GDP. 'Stock market capitalisation' is measured as the total value of all listed shares in a stock market as a percentage of GDP.*

The lack of access to modern electricity services in SSA is often linked to affordability issues (Onyeji et al., 2012; Eberhard, 2011; IEA, 2017; Bos et al., 2018), which arise in both the supply of and demand for electricity access. Supply side issues relate to limited financial resources available to undertake substantial investments in new generation and expansion of the existing grid, and/or to provide off-grid (mini-grid and standalone) solutions to reach currently unelectrified customers. Demand side issues relate to the limited ability of end-customers to pay for the initial connection (Lee et al., 2016, 2019, 2020), standalone off-grid solution or appliances needed for electricity use (Blimpo and Cosgrove-Davies, 2019; Waldron and Hacker, 2020). Consumer financing is, however, not widely available in SSA, often meaning that basic services are out of reach for people in SSA (Waldron and Hacker, 2020).

Constrained financing options are cited among the key drivers of low demand for access solutions, especially among poorer rural households (Karlan et al. 2014; Blimpo and Cosgrove-Davies, 2019; Lee et al., 2020). This means that in the absence of adequate financing options, even though the lifetime costs of electricity access are generally lower than the costs of alternatives, especially when measured based on the cost per lumen-hours (Bhatia and Angelou, 2015), people and small businesses in countries affected by low electricity access often cannot afford to pay for the initial connection or even a solar lantern in cash up-front. This is because the cost of the initial connection and the appliances needed for electricity use generally represent a multiple of a household's monthly income and households lack sufficient savings (Lee et al., 2020).[5]

[5] According to 2017 Global Findex database, in SSA, 46% of adults (aged 15+) were not able to save at all in the past year and only 15% of people were able to save some money at a financial institution (GFDD, 2019).

Low income levels especially among rural households in SSA and constraints on financing, limit affordability, which in turn translates into a low willingness to pay (WTP) for access (Blimpo and Cosgrove-Davies, 2019). For example, Lee et al. (2016, 2019, 2020) conducted experimental research in which they elicited WTP for electricity access to the main grid by offering four different levels of connection charges to households in rural Kenya. They found that the households' WTP is below the costs of providing access, suggesting that electrification would result in a welfare loss. The authors themselves, however, say that demand for access and WTP may be low because of market failures, including credit constraints or a lack of knowledge about the long-term benefits of access.

It would be interesting to see how the findings of this experiment would have changed, had credit constraints been lifted by asking households to pay for example a \$30 initial deposit and a monthly payment of \$1.55 for the next 10 years, assuming a social discount rate of 6%, instead of a one-off payment of \$171, which was the official connection cost achieved with the Last Mile Connectivity Project in Kenya.[6] Furthermore, a recent study by Do and Jacoby (2020) showed that asking households to pay a full connection fee ex-ante might lead to socially undesirable outcomes when households are forming habits and when households cannot know the lifetime benefits of access. The authors relying on experimental evidence showed that ex-post willingness to pay is significantly above ex-ante willingness to pay, while the research by Lee et al. (2016, 2019, 2020) and household decision whether to connect were based on ex-ante WTP.

Research by Blimpo and Cosgrove-Davies (2019) finds that twice the number of households would pay the full price of connection in monthly instalments over a period of two years than would pay just half the price of connection as a one-off payment. A lack of financing options to make connection charges affordable is cited as a reason for the high up-front charges for a grid connection that in turn create a barrier to access (Golumbeanu and Barnes, 2013). This would provide a rationale for the public sector or private investors to provide the financing needed for connections if funding can be raised at lower cost, and/or to design tariffs that allow for a deferred payment until

[6] The connection fee offered to households in the experiment were US\$0, US\$171, US\$284 and US\$398. Apart from the free grid connection offer when take-up was almost universal, the connection charge represented a significant share of the household's income and was likely unaffordable for many, if not most, of the rural households, as noted by Lee et al. (2016). Janssens et al. (2021) based on data from financial diaries of a population drawn from low-income rural villages in Kenya reports average household's total savings of Ksh 13,000, corresponding to approximately 118 US\$ using the foreign exchange rate released by the Central Bank of Kenya on 23rd of January 2021. I note, however, that these households were selected from a population of households fulfilling the study eligibility criteria, and might not be representative of an average rural household in Kenya.

habits are formed (i.e. allowing consumers' future-selves to subsidize their present-selves), as argued by Do and Jacoby (2020). The ability to provide financing, thus overcoming credit constraints that people and utilities in SSA face on a day to day basis has therefore the potential to soften affordability issues, unlock latent demand for electricity, and support access to and use of electricity, especially in situations where consumers lack awareness about the lifetime benefits of access (Bonan et al., 2017; Waldron and Hacker, 2020; Do and Jacoby, 2020).

This suggests an important interdependence between the availability of financial services and energy access in the context of the developing countries. While access to banking systems and capital markets in SSA remains very limited as shown in **Table 1**, financial developments and new means of payments (mobile accounts, mobile payments) have helped to increase access to modern energy services (CGAP, 2016; UN, 2018a; CGAP, 2018). Indeed, digital payments have enabled solar companies to enter the market with pay-as-you-go energy services, giving millions of low-income households around the world access to modern energy services for the first time in their lives (UN, 2018a). Access to these energy services and paying for these on a timely and regular basis can then help households and small businesses establish a credit rating, which in turn facilitates their access to asset ownership and formal banking services (UN, 2018b).

Intrigued about the limited access to both financial services and modern energy solutions in some parts of the world, despite being vital for economic development, poverty eradication and the achievement of other SDGs, as well as the role financial development can play in promoting economic growth, I wanted to answer the following questions:

Questions related to financial development:

- *Q1: Does development of the financial sector support economic growth?*
- *Q2: Are some types of financial structures more conducive to growth than others?*
- *Q3: Could it be the case that the impact of the financial sector is stronger/weaker in some regions than others?*

Questions related to electricity access:

- *Q4: Is achieving SDG 7 realistic in view of the recent rate of progress?*

- *Q5: How much it would cost to achieve SDG 7 by the target year of 2030 (i.e. the year by when SDGs are supposed to be met)?*
- *Q6: Would increased regional trade reduce the overall costs of supply and hence contribute towards achieving SDG 7?*

To answer the first set of questions, I first looked at the importance of financial development for promoting economic growth. This question is especially important considering discussions showing conflicting findings on the link between finance and growth (see Demirgüç-Kunt and Levine, 1996; Levine, 2002, 2003; Beck and Levine, 2004; Luintel et al., 2008; and Demirgüç-Kunt et al., 2013, among others). To shed light on this important question, I relied on meta-analysis techniques that have been increasingly used in economic research as a quantitative way to analyse and summarise research findings (for example, Stanley and Jarrell, 1989; Card and Krueger, 1995; Stanley, 2001; Disdier and Head, 2008; Doucouliagos and Stanley, 2009) and that allow for the correction of any possible publication bias that can arise in published studies (Stanley, 2005).

I was also intrigued by why the results of empirical papers on the link between finance and growth nexus looking at the same topic vary so much, and whether the wide variation in research findings could be driven by something more than just the use of different methods of estimation (for example, from addressing or ignoring endogeneity). In other words, I wanted to understand whether the importance of financial development in promoting economic growth could be explained by real heterogeneity in the effect. That is, whether the size of the effect could vary by the type of financial structure of a country (i.e. a more bank or financial markets-oriented structure[7]), by region or by time period, a finding that has been supported by a number of studies (for example, Fecht et al, 2008; Rousseau and Wachtel, 2011; Luintel et al., 2008).

Finally, my motivation was not only to answer the above questions but also to bridge the gap in the existing research given there had been no comprehensive meta-analysis conducted on this subject despite the conflicting results on the finance-growth nexus found in the primary studies. For example, some research shows that the complexity of financial markets may contribute to financial crises, which occur regularly around the world and often cause a long-lasting decrease in growth rates (Kindleberger, 1978).

[7] Financial structure refers to the size of financial institutions (such as, banks and insurance companies) relative to the size of financial markets (such as, stocks and bond markets).

Having answered the first set of questions related to financial development and in view of the inclusion of access to modern energy services as one of the 17 SDGs, my focus turned to the energy sector. In particular, I wanted to understand whether achieving SDG 7 is realistic in view of the different starting points of different countries and their uneven recent rate of progress, and quantitatively estimate the incremental costs of doing so. A multi-region power system expansion model is well suited to undertake this type of analysis. Several studies have focussed on estimating the costs of expanding the power sector in SSA. To the best of my knowledge, the most comprehensive studies for the region that relied on formal power sector modelling include Rosnes and Vennemo (2012) and Castellano et al. (2015). Those studies, however, looked at the overall costs of serving not only the incremental newly connected households, but also the costs of supply to existing customers whose demand grows over time. Therefore, the derived costs tend to overstate the true cost of access because they do not isolate the incremental costs of only new household connections. As a result, policymakers, might underinvest in access compared to the efficient level of investment. Another study, by Spalding-Fecher et al. (2017), estimates the forward-looking cost of generation in the Southern African Power Pool (SAPP) region to 2070. Electricity trade flows are, however, are an exogenous input to the model, which I see as an important limitation of such type of analysis.[8] Therefore, I wanted to bridge this gap in the current literature.

Today several energy modelling frameworks are available such as OSeMOSYS (Howells et al., 2011), MESSAGE (IAEA, 2016), MARKAL and TIMES (Loulou et al., 2005; Loulou, 2016). While these modelling frameworks could have been potentially adapted to fit my research objectives by applying a more detailed representation of time, adding constraints regarding reserve margins, and similar, a detailed least-cost generation and interconnection expansion model was developed to study the questions at hand. The model allows to estimate the overall forward-looking generation costs and interconnector expansion costs subject to meeting the load forecast within the planning horizon, with the load forecast varying by the target rate of electricity access. The least cost power system expansion model was developed in GAMS (General Algebraic Modelling System), a widely used language for matrix algebra and mathematical programming.

[8] Other studies undertaken for the region did not rely on a dynamically optimised power generation model (e.g. Bazilian et al., 2012; Bazilian et al., 2014; Castellano et al., 2015).

The innovation of this research should be therefore viewed as the specific application of the model, looking at generation options in the region as a way of lowering the affordability barrier to providing electricity access and with the objective to provide specific policy recommendations. However, it is worth emphasising that similar modelling frameworks are available, some of which are open-source, and researchers familiar with those frameworks could rely on and adapt them so that similar questions to those asked in this research could be explored in SSA or other regions.

While initially I focussed my analysis on the whole SSA region, where approximately two thirds of those people with no access to electricity currently live (IEA, 2020), for the optimisation model I had to limit the calculation to a group of countries given the extensive volume of power sector data needed to be compiled for such a study. That is, I limited the analysis to a group of twelve countries in the Southern African Power Pool (SAPP), whose power sectors are interconnected (Botswana, Democratic Republic of Congo, Lesotho, Mozambique, Namibia, South Africa, Swaziland, Zambia, and Zimbabwe) or are planned to be interconnected (Angola, Tanzania and Malawi).

Furthermore, the power sector expansion model allows transmission flows between countries to dynamically adjust so as to reduce the overall cost of supply. This is of particular note in view of the existing research showing the importance of regional integration in reducing the costs of supply as well as improving security of supply (e.g. Bowen et al., 1999; Graeber et al., 2005; Gnansounou et al., 2007; Timilsina and Toman, 2016). Therefore, I look at the potential of cross border trade in electricity to drive down the costs of supply in SAPP, thus helping to overcome one of the key causes of low electricity access related to low affordability.

The remainder of this thesis is structured as follows. In Chapter 2, I quantitatively analyse 1334 estimates from 67 studies that examine the relationship between financial development on economic growth. In Chapter 3, I estimate the costs of providing access to electricity in Sub-Saharan Africa for a group of countries in SAPP. In Chapter 4, I estimate how the costs of providing access to electricity in the SAPP region could be decreased by increased power trade in the region. Chapter 5 provides general conclusions about the findings and conclusions reached in this thesis.

Several annexes are included to this thesis that provide further detail on my analysis and assumptions used in the calculations:

- Annex 1 provides a list of primary studies used in the meta-analysis;
- Annex 2 provides detail on the current state of electricity access in SSA, its recent development, and its outlook under the current state of progress;
- Annex 3 provides a mathematical description of the least-cost power sector expansion model;
- Annex 4 summarises the extensive power system data used in the analysis;
- Annex 5 summarises the current interconnector transfer capacity together with possible future interconnector transfer capacity in the SAPP region;
- Annex 6 provides detail on the current and future level of on-grid electricity demand under the different scenarios for electricity access;
- Annex 7 provides the core code developed for the GAMS model;
- Annex 8 provides selected detailed results.

This thesis also benefited from comments received from my opponents as part of the pre-defence of my dissertation thesis and discussions and additional recommendations were also received during my pre-defence held in October 2020. Annex 9 provides an overview of the comments received as well as my replies to the comments and how these recommendations have been addressed in this revised version of my dissertation thesis.

**References (Chapter 1)**


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# Chapter 2

# Financial Development and Economic Growth: A Meta-Analysis

**The results of this chapter were published as**: Valickova, P., Havranek, T., Horvath, R., 2015. Financial development and economic growth: A meta-analysis. Journal of Economic Surveys 29, 506–526. https://doi.org/10.1111/joes.12068

**Abstract**: We analyse 1334 estimates from 67 studies that examine the relationship between financial development and economic growth. Taken together, the studies imply a positive and statistically significant effect, but the individual estimates vary widely. We find that both research design and heterogeneity in the underlying effect play a role in explaining the differences in research findings. Studies that do not address endogeneity tend to overstate the importance of finance for economic growth. While the relationship seems to be weaker in poorer countries, the effect decreases worldwide after the 1980s. Our results also suggest that the role of stock markets in enhancing economic growth could be more important than that of other financial intermediaries. We find little evidence of publication bias in the literature.

**Keywords**: Development, Finance, Growth, Meta-Analysis

**JEL classification**: C83, G10, O40.

# 2.1. Introduction

Does development of the financial sector support economic growth? On the one hand, we observe that financial intermediaries and markets in developed countries display substantial complexity, and some researchers suggest a causal effect from financial development on economic growth (for example, Levine et al., 2000; Rajan and Zingales, 1998). On the other hand, the complexity of financial markets may contribute to financial crises, which occur regularly around the world and often cause a long-lasting decrease in growth rates (Kindleberger, 1978).

In this paper, we quantitatively review the empirical literature on the finance–growth nexus. We focus on three fundamental questions. First, does financial development foster economic growth? Second, are some types of financial structure more conducive to growth than others? This is important in the light of the recent discussion showing conflicting findings about the importance of different financial structures on growth (see Demirguc-Kunt and Levine, 1996; Levine, 2002, 2003; Beck and Levine, 2004; Luintel et al., 2008; Demirguc-Kunt et al., 2013; among others). Third, could it be the case that the role of the financial sector is stronger/weaker in some regions than others?

To examine these issues and to quantitatively summarise the existing evidence in the field of financial development and economic growth, we rely on meta-analysis techniques.[9] Although originally developed for use in medicine, meta-analysis has been increasingly used in economic research (see, for example, Card and Krueger, 1995; Stanley and Jarrell, 1989; Stanley, 2001; Disdier and Head, 2008; Doucouliagos and Stanley, 2009; Daniskova and Fidrmuc, 2012). To our knowledge, this is a first attempt to conduct a comprehensive meta-analysis of the relationship between financial development and economic growth, thus we aim to bridge an important gap in the finance and growth literature. The closest paper to ours is that of Bumann et al. (2013), who use meta-analysis to document in the related literature a positive but relatively weak effect of financial liberalization on growth.

[9] For guidelines discussing the techniques of meta-analysis in economics, we refer the reader to Stanley et al. (2013) and Havranek et al. (2020). The revised meta-analysis guidelines by Havranek et al. (2020) developed for the Meta-Analysis of Economics Research Network (MAER-Net) summarise some novel meta-analysis techniques used since the time of publishing our research findings. Some novel approaches include weighted average of adequately powered estimates, unrestricted weighted least squares, the selection model, the p-uniform model, the endogenous kink model, and the stem-based estimator. Bayesian model averaging (BMA) and frequentist model averaging techniques have also become increasingly popular tools to address the model uncertainty around the choice of appropriate regression model specifications and to report findings alongside the results of a multivariate meta-regression analysis. BMA has also become increasingly popular as a tool to correct for potential misspecifications in the literature, which in the field of finance and growth could be for example not addressing for the issue of endogeneity in primary studies. For the use of BMA in the field of economics we refer the reader to Havranek and Sokolova (2020), Bajzik et al. (2020), Gechert et al. (2020) or Cazachevici et al. (2020).

Our results suggest that the literature identifies an authentic positive relationship between financial development and economic growth. We argue that the estimates of the effect reported in the literature are not overwhelmingly driven by so-called publication selection bias, that is, the preference of researchers, referees or editors for positive and significant estimates. The results also indicate that the differences in the reported estimates arise not only from the research design (for example, from addressing or ignoring endogeneity), but also from real heterogeneity in the effect. To be specific, we find that the effect of financial development on growth varies across regions and time periods. The effect weakens somewhat after the 1980s and is generally stronger in wealthier countries, a finding consistent with Rousseau and Wachtel (2011). Our results also suggest that financial structure is important for the pace of economic growth, as suggested, for example, by Demirguc-Kunt and Levine (1996). We further find that stock market-oriented systems tend to be more conducive to growth than bank-oriented systems, which is in line with the theoretical model of Fecht et al. (2008) or empirical evidence by Luintel et al. (2008).

The remainder of this chapter is structured as follows. In Section 2.2, we discuss the key channels through which financial systems can have a positive impact on economic growth, together with measures of financial development used in empirical studies. In Section 2.3, we describe how we collect the data from the literature, and we provide summary statistics of the data set. In Section 2.4, we test for the presence of publication selection. In Section 2.5, we examine the sources of heterogeneity in the reported estimates on finance and growth. Section 2.6 concludes this chapter, and the online annex available at *http://meta-analysis.cz/finance_growth/* provides the primary data set collected for this study and a list of studies included in the meta-analysis. We also list the primary studies included in the meta-analysis in **Annex 1** to this thesis.

## 2.2. Financial Development and its Measurement

Economic theory states that well-functioning financial markets have the potential to reduce information and transaction costs, leading to better resource allocation and therefore exerting a positive impact on economic growth (King and Levine, 1993; Beck and Levine, 2004). Levine (1997; 2005) defines five primary functions of financial systems through which financial systems have the potential to enhance the growth process. These are: acquiring information and allocating resources, exercising corporate control, mobilizing savings, facilitating the exchange of goods and services, and reducing risk. Further to these, Coricelli and Roland (2008) asserted that financial systems have also an important role in acting as a shock absorber by spreading risks among more market players at times of adverse economic shocks.[10] Beyond overall economic growth, finance also matters for the life and wellbeing of individuals and has the potential to enable a more inclusive growth path (Stein, 2013; OECD and World Bank, 2006). Having access to financial services can help individuals invest in their future such as investing in education or saving for retirement, engage in entrepreneurial activities, better manage risk, and smooth their income and hence deal with hardships and shocks affecting their daily income (OECD and World Bank, 2006; Demirgüç-Kunt et al., 2018). The school of thoughts arguing the crucial importance of financial system development for economic growth can be traced back to Bagehot (1873) and Schumpeter (1911).

Despite this, the positive link between financial development and economic growth has been subject to debate, with some arguing its irrelevance for the growth process and some pointing to its negative impact. For example, Robert Lucas, the winner of the 1995 Nobel Prize in Economics argued that economists "*badly over-stress*" the role of financial matters in economic growth (Lucas, 1988, p.6). Keynes (1936), Kindleberger (1978) and Minsky (1991) argued that speculation inherent in some types of financial markets can have a destabilizing impact on the economy, thus leading to periods of profound crisis and long-lasting decrease in growth rates. Since then, conflicting findings on the importance of financial development for economic growth were supported by a number of empirical studies, including Demirgüç-Kunt and Levine (1996), Beck and Levine (2004), Luintel et al. (2008), and Demirgüç-Kunt et al. (2013), among others.

In order to shed some light on why the results of empirical studies in this field vary so much, a number of narrative literature reviews have been written on this topic. These include thorough reviews by Levine (2005) and Ang (2008), who also provide a good overview of the different methodology used in the literature to estimate the link between financial development and economic growth.

Narrative literature reviews, however, suffer from several shortcomings as discussed by Stanley (2001), including deriving different results on the same topic

[10] Coricelli and Roland (2008) on a sample of 115 countries over the period 1963 to 2004 showed that economies with less developed financial sectors tend to experience sharper output declines in periods of negative economic shocks. The authors also found that this effect gains on importance in periods of sharp output falls.

because of the subjectivity inherent in these reviews Borenstein (2009). Meta-analysis as a quantitative literature review has therefore become increasingly used as a way to objectively summarise research findings in a more systematic and transparent way with a primary objective to shed more light on the variation in the research findings. This is notably the case of the finance-growth literature. One of the aspects of variation in research findings, which also has been discussed in the narrative literature reviews is the measurement of financial development.

The Financial Development Report 2011 published by the World Economic Forum defines financial development as '*the factors, policies, and institutions that lead to effective financial intermediation and markets, as well as deep and broad access to capital and financial services*' (WEF, 2011, p. 13). This definition gives major importance to well-functioning and effective financial intermediation. In a similar vein, Levine (1999, p. 11) puts forward that an ideal measure of financial development would capture '*the ability of the financial system to research firms and identify profitable ventures, exert corporate control, manage risk, mobilize savings, and ease transactions*." These definitions assign a major role to the effectiveness of financial intermediaries and stock markets. Empirical studies must, however, operationalize these definitions and find good proxies for financial development, which may present the greatest challenge for the literature (Edwards, 1996), which can be especially true for developing countries where reliable data is often lacking. For example, high credit growth does not necessarily imply smooth financial intermediation as the use of the typical indicators, such as the credit-to-GDP (gross domestic product) ratio implicitly assumes. In contrast, faster credit growth can indicate unbalanced allocation of financial resources and signal an upcoming financial crisis.[11]

The most commonly used indicators of financial development used in the empirical literature can be broadly defined as financial depth, the bank ratio, and financial activity, with financial depth being the most commonly used in the primary studies identified in this research. Financial depth, measured as the ratio of liquid liabilities of the financial system to GDP, reflects the size of the financial sector. Researchers employ various measures of financial sector depth, which are typically connected to the money supply: some authors use the ratio of M2 to GDP (for example, Giedeman and Compton, 2009; Anwar and Cooray, 2012), while others rely on M3 (Dawson, 2008;

[11] See Arcand et al. (2012), Cecchetti and Kharroubi (2012), and Beck et al. (2013) for evidence that fast-growing financial markets may have adverse effects on economic growth.

Huang and Lin, 2009; Hassan et al., 2011). The use of the broader aggregate, M3, is driven by the concern that the ratio of M2 to GDP does not appropriately capture the development of the financial system in countries where money is principally used as a store of value (Yu et al., 2012). To eliminate the pure transaction aspect of narrow monetary aggregates, some authors prefer the ratio of the difference between M3 and M1 to GDP (for example, Rousseau and Wachtel, 2002; Yilmazkuday, 2011). Financial depth, however, is a purely quantitative measure and does not reflect the quality of financial services. In addition, financial depth may include deposits in banks by other financial intermediaries, which raises the problem of double counting (Levine, 1997).

The second proxy used to measure financial development is the bank ratio, first applied by King and Levine (1993). The bank ratio is defined as the ratio of bank credit to the sum of bank credit and domestic assets of the central bank. The bank ratio stresses the importance of commercial banks compared with central banks in allocating excess resources in the economy. Nevertheless, Levine (1997) notes that there are weaknesses associated with the implementation of this measure, as financial institutions other than banks also provide financial functions. Moreover, the bank ratio does not capture to whom the financial system is allocating credit, nor does it reflect how well commercial banks perform in mobilizing savings, allocating resources, and exercising corporate control.

The third proxy used in the literature is financial activity. Researchers employ several measures of financial activity, such as the ratio of private domestic credit provided by deposit money banks to GDP (for example, Beck and Levine, 2004; Cole et al., 2008); the ratio of private domestic credit provided by deposit money banks and other financial institutions to GDP (employed by De Gregorio and Guidotti, 1995; Andersen and Tarp, 2003); and the ratio of credit allocated to private enterprises to total domestic credit (employed by King and Levine, 1993; Rousseau and Wachtel, 2011). These measures offer a better indication of the size and quality of services provided by the financial system because they focus on credit issued to the private sector. However, neither private credit nor financial depth can adequately assess the effectiveness of financial intermediaries in smoothing market frictions and channelling funds to the most productive use (Levine et al., 2000).

The empirical research in this area originally focused on banks. Later, researchers started to examine the effect of stock markets as well (Atje and Jovanovic, 1993), and as a consequence, proxies for stock market development have become increasingly used.

The most commonly employed measures of stock market development are the market capitalization ratio (Shen and Lee, 2006; Chakraborty, 2010; Yu et al., 2012), stock market activity (Manning, 2003; Tang, 2006; Shen et al., 2011), and the turnover ratio (Beck and Levine, 2004; Liu and Hsu, 2006; Yay and Oktayer, 2009). Stock market capitalization refers to the overall size of the stock market and is defined as the total value of listed shares relative to GDP. The other two measures are associated more with liquidity. Stock market activity equals the total value of traded shares relative to GDP, while the turnover ratio is defined as the total value of traded shares relative to the total value of listed shares.

Alternative measures of financial development include, for example, the aggregate measure of overall stock market development (Naceur and Ghazouani, 2007), which considers market size, market liquidity, and integration with world capital markets; the share of resources that the society devotes to its financial system (Graff, 2003); the ratio of deposit money bank assets to GDP (Bangake and Eggoh, 2011); and financial allocation efficiency, which is defined as the ratio of bank credit to bank deposits.

The preceding paragraphs suggest that the literature offers little consensus concerning the most appropriate measure of financial development. For this reason, most researchers relied on several definitions of financial development to corroborate the robustness of their findings. Different indicators are also suited to different countries depending on whether the country features a financial system oriented on banks or on the stock market. Furthermore, the focus of the empirical literature on indicators of financial depth, the bank ratio and financial activity, was also driven by data availability. More recently, Cihak et al. (2012) and Demirgüç-Kunt and Klapper (2012) introduced the Global Financial Development Database and the Global Financial Inclusion Database, filling a considerable gap in the data on different aspects of financial development, especially for developing countries where data tends to be even more limited. These databases provided a new, large cross country dataset on financial system characteristics which not only covers measures of the size of financial institutions and markets but also measures of the efficiency of financial intermediaries and markets, financial stability, and the degree to which individuals have access to financial services.

# 2.3. The Data Set of the Effects of Finance on Growth

A wide number of studies has been written on this subject, examining the relationship between financial development and economic growth, and analysing whether higher levels of financial development are associated with higher levels of economic growth. These studies relied on wide range of data examining different time periods, different regions and countries at different stage of development, and relying on different econometric methods.[12] As a first step in our meta-analysis, we collect data from the empirical studies, these are referred to as primary studies. In doing so, we focus on studies that estimate a variant of the classical growth model augmented for financial development:

$$PCC_{ij} = \alpha + \beta F_{it} + \gamma X_{it} + \eta_i + \varepsilon_{it}, \tag{1}$$

where $i$ and $t$ denote country and time period subscripts; $G$ denotes a measure of economic development[13]; $F$ stands for a measure of financial development; $X$ is a vector of control variables accounting for other factors considered important in the growth process (for example, initial income, human capital, international trade, or macroeconomic and political stability); $\delta_t$ captures a common time-specific effect; $\eta_i$ denotes an unobserved country-specific effect; and $\varepsilon$ is the unobserved error term. The estimated regression coefficient $\beta$ from equation (1), is the regression coefficient of interest (i.e., the coefficient estimating the relationship between financial development and economic growth). Note that (1) describes a general panel data setting, which can collapse to cross-sectional or time-series models. The cross-sectional and time-series studies are analysed in the following sections, too.

Different econometric methods have been used in the financial development-economic growth empirical literature. Some studies use a fixed effects (FE) model to

[12] For an overview of the empirical studies examining the effect of financial development on economic growth, methodologies used to study their relationship, as well as a discussion on the wide variety of empirical findings derived from diverse studies using different estimation techniques, specifications and data characteristics, we refer the reader to Levine (2005), Ang (2008) and Valickova (2012).

[13] Different measures of economic development are used in the empirical growth literature. Among the empirical studies studying the relationship between financial development and economic growth, researchers most frequently use GDP growth or per capita GDP growth as the dependent variable measured either in real or nominal terms. Other possible growth indicators sometimes used are the rate of capital accumulation per capita or improvements in economic efficiency (used for example in the pioneering work of King and Levine, 1993) or human capital development (Outreville 1999). However, as the focus of the present study is classical growth regressions, only studies using GDP growth rates as the dependent variable are considered.

control for specific country characteristics, which solves the issue of omitted variable bias due to unobserved country or region-specific effects. However, this technique does not specifically deal with the issue of endogeneity bias. On the other hand, a random effects (RE) model addresses the issue of endogeneity but does not address the bias resulting from country specific effects. Hence, both FE and RE provide only half of the solution to the problem of omitted variable bias and simultaneity bias. Tsangarides (2002) discusses these issues in detail. The Generalized Method of Moments (GMM) estimator has been increasingly used in the finance-growth empirical research to addresses both the issue of endogeneity, as well as the issue of omitted variable bias.[14]

With respect to the inclusion of primary studies in the present meta-analysis, we consider all the empirical studies mentioned in the literature review of Ang (2008). Moreover, we search in the Scopus database and identify 451 papers for the keywords 'financial development' and 'economic growth'. We read the abstracts of the papers and retain any studies that demonstrate a chance of containing empirical estimates regarding the effect of finance on growth. Overall, this approach leads to 274 potential studies. We terminate the literature search on April 10, 2012. Our approach here, as well as in other aspects of this meta-analysis, conforms to the Meta-Analysis of Economics Research Reporting Guidelines (Stanley et al., 2013).

We read the 274 potential studies to see whether they include a variant of the growth model as shown in equation (1). We only collect published studies because we consider publication status to be a simple indicator of study quality. Rusnak et al. (2013), for example, found that there is little difference in the extent of publication bias between published and unpublished studies, and we correct for the potential bias in any case. Furthermore, we only include studies reporting a measure of the precision of the effect of finance on growth (that is, studies that contain standard errors, t-statistics, or p-values) because precision is required for modern meta-analysis methods. Finally, to increase the comparability of the estimated effects, we only include studies where the dependent variable is the growth rate of total GDP or GDP per capita in real or nominal terms. Limiting the number of studies was also important in view of the high number of

[14] The GMM estimator was first applied to investigate the relationship between financial development and economic growth by Levine (1998), Rousseau and Wachtel (2000) and Levine et al. (2000). Based on the GMM estimation results, Levine et al. (2000, p. 44) note: "*we can safely discard the possibility that the relationship between financial intermediary development and growth is due to simultaneity bias or to omitted variables*". The properties of a system GMM estimator and especially its ability to deal with endogeneity problem render it now the most commonly used econometric method in the empirical growth literature and is often referred to as a best practice estimator for dynamic panels. Other methods used to address endogeneity issues in the field of finance and growth include relying on the instrumental variable estimator, two-stage least squares and estimating a lagged effect of financial development on economic growth. For a general overview of methods used in the empirical literature, we refer the reader to Valickova (2012), Levine (2005) and Ang (2008).

studies conducted in this field, especially had unpublished studies and studies considering a different specification of the dependent variable been included.

The resulting data set contains 67 studies[15], which are listed in the online annex at http://meta-analysis.cz/finance_growth/ and also provided in **Annex 1** of this thesis. Because most studies report multiple estimates obtained from different specifications (for example, using a different definition of financial development), it is difficult to select a representative estimate for each study. For this reason, we collect all estimates, which provides us with 1334 unique observations.[16] It seems to be best practice in meta-analyses to collect all estimates from the relevant studies (for instance, Disdier and Head, 2008; Doucouliagos and Stanley, 2009; Daniskova and Fidrmuc, 2012). We also codify variables reflecting study characteristics that may influence the reported estimates of the effect of finance on growth, and these variables are described in Section 2.5.

As discussed above, we are interested in coefficient $\beta$ from equation (1): the regression coefficient reported in a growth model for financial development. Nevertheless, as different studies use different units of measurement, the estimates are not directly comparable. To summarize and compare the results from various studies, we need standardized effect sizes. We use partial correlation coefficients (r), as they are commonly used in economic meta-analyses (Doucouliagos, 2005; Doucouliagos and Ulubasoglu, 2006; Doucouliagos and Ulubasoglu, 2008; Efendic et al., 2011). The partial correlation coefficients can be derived from the t-statistics of the reported regression estimate and residual degrees of freedom (Greene, 2008):

$$r_{ij} = \frac{t_{ij}}{\sqrt{t_{ij}^2 + df_{ij}}} \tag{2}$$

where $r_{ij}$ denotes the partial correlation coefficient from the $i^{th}$ regression estimate of the $j^{th}$ study; $t$ is the associated t-statistic; and $df$ is the corresponding number of degrees of freedom. The sign of the partial correlation coefficient remains the same as the sign of the coefficient $\beta$, which is related to financial development in equation (1).

[15] We note that 67 studies is relatively high and implies significant time to code all the characteristics of the primary studies.

[16] When multiple proxies for financial development are included in the same regression, we collect the estimated coefficients for all of them, but use a dummy variable in the analysis to see whether these estimates are significantly different from the rest of the sample. Multiple estimates reported in one study are also likely to be correlated, which we take into account by using mixed-effects multilevel methods in the analysis.

For each partial correlation coefficient, the corresponding standard error must be computed to employ modern meta-analysis techniques. The standard error can be derived employing the following formula (Fisher, 1954):

$$SEr_{ij} = \frac{r_{ij}}{t_{ij}} \tag{3}$$

where $SEr_{ij}$ represents the standard error of the partial correlation coefficient $r_{ij}$ and $t_{ij}$ is, again, the t-statistic from the $i^{th}$ regression of the $j^{th}$ study.

Because the partial correlation coefficients are not normally distributed, we use Fisher z-transformation to obtain a normal distribution of effect sizes (Card, 2011):

$$Zr_{ij} = 0.5 \ln\left(\frac{1+r_{ij}}{1-r_{ij}}\right) \tag{4}$$

This transformation enables us to construct normal confidence intervals in the estimations. These z-transformed effect sizes are used for the computations and then transformed back to partial correlation coefficients for reporting.

Of the 1334 estimates of the effect of finance on growth in our sample, 638 are positive and statistically significant at the 5% level, 446 are positive but insignificant, 128 are negative and significant, and 122 are negative but insignificant. These numbers indicate substantial heterogeneity in the reported effects. **Table 2** presents summary statistics for the partial correlation coefficients as well as their arithmetic and inverse variance weighted averages.

**Table 2: Partial Correlation Coefficients for the Relation between Finance and Growth**

| **Observations** | |
|---|---|
| Number of studies | 67 |
| Number of estimates | 1334 |
| Median r | 0.14 |
| **Averages** | |
| Simple average r | 0.15 (0.095, 0.20) |
| Fixed-effects average r | 0.09 (0.088, 0.095) |
| Random-effects average r | 0.14 (0.129, 0.150) |

Notes: Figures in brackets denote 95% confidence intervals, r stands for partial correlation coefficient.

The arithmetic mean yields a partial correlation coefficient of 0.15 with a 95% confidence interval [0.1, 0.2]. The simple average of the partial correlation coefficients, however, suffers from several shortcomings. First, it does not consider the estimate's precision, as each partial correlation coefficient is ascribed the same weight regardless of the sample size from which it is derived. Second, the simple average does not consider possible publication selection, which can bias the average effect. More appropriate summary statistics that account for the estimate's precision can be computed using the fixed-effects or random-effects model, described in detail by Card (2011) and Borenstein et al. (2009).[17]

The fixed-effects model assumes that all reported estimates are drawn from the same population. To calculate the fixed-effects estimate, we weight each estimate by the inverse of its variance. The model yields a partial correlation coefficient of 0.09 with a 95% confidence interval [0.088, 0.095], which is only slightly less than the simple mean. This result indicates that when we give more weight to larger studies, the average effect decreases, which can be a sign of selection bias. Thus, studies with small sample sizes must find a larger effect to offset high standard errors and achieve statistical significance. We explore this issue extensively in the next section.

All of our results reported thus far rest on the assumption that all the studies measure a common effect. This is not necessarily realistic, because the studies use different data sets and examine different countries. In this case, random effects may provide better summary statistics. The random-effects model, in addition to considering the precision of estimates, accounts for between-study heterogeneity. The method yields a partial correlation of 0.14 with a 95% confidence interval [0.129, 0.15]. Nevertheless, the random-effects model assumes that the differences among the underlying effects are random and thus, in essence, unobservable. We proceed to model explicitly the heterogeneity among effect sizes using meta-regression analysis in the following sections.

## 2.4. Publication Bias

Publication bias, sometimes referred to as the file-drawer problem, arises when researchers, referees, or editors have a preference for publishing results that either support a particular theory or are statistically significant. In a survey of meta-analyses, Doucouliagos and Stanley (2013) examine the extent of publication bias in economics and find that the problem is widespread. For example, Stanley (2005) shows that the bias exaggerates the reported price elasticities of water demand fourfold. Havranek et al.

[17] The terminology here follows hierarchical data modeling, which is commonly used in meta-analysis. Fixed effects, therefore, have a different meaning from the one that is common in econometrics, and imply the absence of random effects.

(2012) find that after correcting for publication bias, the underlying price elasticity of gasoline demand is approximately half of the average published estimate. Havranek and Irsova (2012) report substantial publication bias in the literature on spillovers from foreign investment. The economic growth literature is no exception. For example, Doucouliagos (2005) finds bias in the literature regarding the relationship between economic freedom and economic growth, and Doucouliagos and Paldam (2008) identify bias in the research on aid effectiveness and growth.

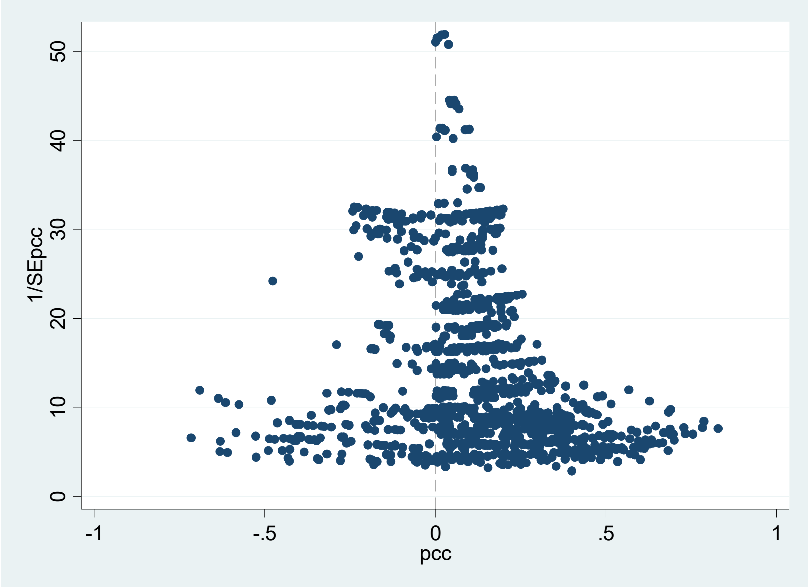
Publication bias is particularly strong in fields that show little disagreement concerning the correct sign of the parameter. As a consequence, estimates supporting the prevailing theoretical view are more likely to be published, whereas insignificant results or results showing an effect inconsistent with the theory tend to be underrepresented in the literature. Nevertheless, not all research areas in economics are plagued by publication bias, as several meta-analyses demonstrate (for example, Doucouliagos and Laroche, 2003; Doucouliagos and Ulubasoglu, 2008; Efendic et al., 2011). For a thorough discussion of the presence of publication bias in the empirical economics research, we refer the reader to Christensen and Miguel (2018).

The commonly used tests of publication bias rest on the idea that studies with smaller samples tend to have large standard errors; accordingly, the authors of such studies need large estimates of the effect to achieve the desired significance level. Thus, authors with small samples may resort to a specification search, re-estimating the model with different estimation techniques, data sets, or control variables until the estimates become significant. In contrast, studies that use more observations can report smaller effects, as standard errors are lower with more observations and statistical significance is then easier to achieve.

A typical graphical method used to examine possible publication bias is the so-called funnel plot (Stanley and Doucouliagos, 2010). On the horizontal axis, the funnel plot displays the standardized effect size derived from each study (in our case, partial correlation coefficients); on the vertical axis, it shows the precision of the estimates. More precise estimates will be close to the true underlying effect, while imprecise estimates will be more dispersed at the bottom of the figure. Therefore, in the absence of publication selection, the figure should resemble a symmetrical inverted funnel.[18] The funnel plot for the literature on finance and growth is depicted in **Figure 1**.

[18] The tip of the funnel does not have to be zero in general; it denotes the most precise estimates. The funnel can be symmetrical even if the true effect was positive or negative (see, for instance, Krassoi Peach and Stanley, 2009).

**Figure 1**: **A Funnel Plot of the Effect of Finance on Growth**




Though the cloud of observations in **Figure 1** resembles an inverted funnel, a closer visual inspection suggests an imbalance in the reported effects, as the right-hand side of the funnel appears to be heavier. This finding suggests that positive estimates may be preferably selected for publication. However, visual methods are subjective, and therefore, in the remainder of the section, we focus on formal methods of detection of and correction for publication bias. We follow, among others, Stanley and Doucouliagos (2010), who regress the estimated effect size on its standard error:

$$PCC_{ij} = \beta_0 + \beta_1 SEpcc_{ij} + \mu_{ij}\,;\; j = 1, \ldots, N\,;\; i = 1, \ldots, S, \tag{5}$$

where $N$ is the total number of studies, $i$ is an index for a regression estimate in a $j^{th}$ study, and each $j^{th}$ study can include $S$ regression estimates. The coefficient $\beta_1$measures the magnitude of publication bias, and $\beta_0$ denotes the true effect.

Nevertheless, because the explanatory variable in (5) is the estimated standard deviation of the response variable, the equation is heteroskedastic. This issue is, in practice, addressed by applying weighted least squares such that the equation is divided by the estimated standard error of the effect size (Stanley, 2008):

$$\frac{r_{ij}}{SEr_{ij}} = t_{ij} = \beta_0\left(\frac{1}{SEr_{ij}}\right) + \beta_1 + \mu_{ij}\left(\frac{1}{SEr_{ij}}\right) = \beta_1 + \beta_0\left(\frac{1}{SEr_{ij}}\right) + v_{ij}, \tag{6}$$

where $SEr_{ij}$ is the standard error of the partial correlation coefficient $r_{ij}$. After transforming equation (5), the response variable in equation (6) is now the t-statistic of the estimated coefficient $\beta$ from equation (1). The equation can be interpreted as the funnel asymmetry test (it follows from rotating the axes of the funnel plot and dividing the new vertical axis by the estimated standard error) and, therefore, a test for the presence of publication bias.[19] Because we use multiple estimates per study, we should control for the potential dependence of estimates within a study by employing the mixed-effects multilevel model (Doucouliagos and Stanley, 2009; Havranek and Irsova, 2011)[20]:

$$t_{ij} = \beta_1 + \beta_0 \left( \frac{1}{SEr_{ij}} \right) + \alpha_j + \epsilon_{ij}, \qquad \alpha_j | SEr_{ij} \sim N(0, \psi), \qquad v_{ij} | SE_{ij},\ \alpha_j \sim N(0, \theta). \tag{7}$$

The overall error term $(v_{ij})$ from (6) now breaks down into two components: study-level random effects $(\alpha_j)$ and estimate-level disturbances $(\epsilon_{ij})$. This specification is similar to employing the random-effects model in a standard panel data analysis, except that the restricted maximum likelihood is used in the estimation to account for the excessive lack of balance in the data (some studies report many more estimates than other studies). The mixed-effects technique gives each study approximately the same weight if between-study heterogeneity is large (Rabe-Hesketh and Skrondal, 2008, p. 75.).

If the null hypothesis of $\beta_1 = 0$ is rejected, we obtain formal evidence for funnel asymmetry, and the sign of the estimate of $\beta_1$ indicates the direction of the bias. A positive constant, $\beta_1$, would suggest publication selection for large positive effects. A negative and statistically significant estimate of $\beta_1$ would, conversely, indicate that negative estimates are preferably selected for publication. Stanley (2008) uses Monte Carlo simulations to show that the funnel-asymmetry test is an effective tool for identifying publication bias.

Rejection of the null hypothesis $\beta_0 = 0$ would imply the existence of a genuine effect of finance on growth beyond publication bias. The test is known as the precision-effect test. Stanley (2008) examines the properties of the test in simulations

[19] Both the left- and right-hand parts of equation (6) are functions of the reported *t*-statistic of the effect of financial development on growth, which raises endogeneity issues. Nevertheless, almost all of the variance in the variable on the right-hand side is determined by the number of degrees of freedom, which makes the endogeneity problem negligible.

[20] An alternative and popular way to handle data dependence is to use weighted least squares and cluster standard errors at the study level. Some authors also use Bayesian methods; see, for example, Irsova and Havranek (2013).

and concludes that it is a powerful method for testing for the presence of a genuine effect and that it is effective even in small samples and regardless of the extent of publication selection.

**Table 3: Test of the True Effect and Publication Bias**

| | |
|---|---|
| 1/SEr (Effect) | 0.199***(0.018) |
| Constant (bias) | -0.353 (0.422) |
| Within-study correlation | 0.46 |
| Observations | 1334 |
| Studies | 67 |

*Notes: The response variable is the t-statistics of the estimated coefficient on financial development. Estimated by mixed effects multilevel model. Standard errors in parentheses,*** denote significance at the 1% level.*

**Table 3** reports the results of funnel asymmetry test. The constant term is insignificant, indicating no sign of publication selection. The statistically significant estimate of $\beta_0$, however, indicates that the literature identifies, on average, an authentic link between financial development and economic growth. According to the guidelines of Doucouliagos (2011), the partial correlation coefficient of 0.2 represents a moderate effect of financial development on economic growth. The guidelines are based on a survey of 41 meta-analyses in economics and the distribution of the reported partial correlations in these studies. The partial correlation coefficient is considered “small” if the absolute value is between 0.07 and 0.17 and “large” if the absolute value is greater than 0.33. If the partial correlation coefficient lies between 0.17 and 0.33, which is the case here, Doucouliagos (2011) considers the effect to be “medium”.

Using the likelihood ratio test, we reject the null hypothesis of no between-study heterogeneity at the 1% level, which is why we report the mixed-effects multilevel model instead of ordinary least squares (OLS). Nevertheless, the specification we use assumes that all heterogeneity in the results is caused only by publication bias and sampling error, an assumption that is not realistic.

# 2.5. Multivariate Meta-Regression

In many studies that examine the finance–growth nexus, researchers emphasize that the estimated effect depends on the estimation characteristics, the proxy measures for financial development, the data span, and the countries included in the estimation (see Beck and Levine, 2004; Ang, 2008; Yu et al., 2012; among others). To determine whether the results systematically vary across the different contexts in which researchers estimate the effect, we employ multivariate meta-regression analyses. The differences in the reported results may stem either from heterogeneity in research design or from real economic heterogeneity across countries and over time. We follow Havranek and Irsova (2011) and estimate the following equation:

$$t_{ij} = \beta_1 + \beta_0 \left(\frac{1}{SEpcc_{ij}}\right) + \sum_{k=1}^{K} \frac{\gamma_k z_{ijk}}{SEpcc_{ij}} + \alpha_j + \varepsilon_{ij}, \tag{8}$$

where Z stands for the set of moderator variables that are assumed to affect the reported estimates, each weighted by $1/SEpcc_{ij}$ to correct for heteroskedasticity, and $K$ denotes the total number of moderator variables. The specification assumes that publication bias ($\beta_1$) varies randomly across studies, and we only model systematic variations in the true effect size ($\beta_0$).

**Table 4** presents the moderator variables that were codified from the primary studies, including their descriptive statistics (means and standard deviations). We divide them into two broad categories: variables related to differences in research design and variables related to real economic differences in the underlying effect of finance on growth.

**Table 4: Description and summary statistics**

| Variable | Description | Mean | Std. dev. |
|---|---|---|---|
| t-statistic | The t-statistic of the estimated coefficient on financial development; the response variable | 1.77 | 3.49 |
| 1/SEr | The precision of the partial correlation coefficient | 14.68 | 9.91 |
| *Data characteristics* | | | |
| No. of countries | The number of countries included in the estimation | 43.13 | 30.19 |
| No. of time units | The number of time units included in the estimation | 11.06 | 18.69 |
| Sample size | The logarithm of the total number of observations used | 4.96 | 1.27 |
| Length | The number of years in time unit | 7.27 | 10.36 |
| Log | = 1 if logarithmic transformation is applied and 0 otherwise | 0.58 | 0.49 |
| Panel (base category) | = 1 if panel data are used and 0 otherwise | 0.62 | 0.48 |
| Cross-section | = 1 if cross-sectional data are used and 0 otherwise | 0.24 | 0.43 |
| Time series | = 1 if time series data are used and 0 otherwise | 0.13 | 0.33 |
| Homogeneous | = 1 if homogeneous sample of countries is considered and 0 otherwise | 0.34 | 0.47 |
| *Nature of the dependent variable* | | | |
| Real GDP per capita (base category) | = 1 if dep. var. in primary regression is growth rate of real GDP per capita and 0 otherwise | 0.72 | 0.45 |
| Nominal GDP per capita | = 1 if dep. var. in primary regression is growth rate of GDP per capita and 0 otherwise | 0.08 | 0.27 |
| Nominal GDP | = 1 if dep. var. in primary regression is growth rate of GDP and 0 otherwise | 0.14 | 0.35 |
| Real GDP | = 1 if dep. var. in primary regression is growth rate of real GDP and 0 otherwise | 0.06 | 0.24 |
| *Proxy measures for financial development* | | | |
| Depth (base category) | = 1 if financial depth is used as indicator of FD and 0 otherwise | 0.33 | 0.47 |

| Variable | Description | Mean | Std. dev. |
|---|---|---|---|
| Financial activity | = 1 if private domestic credit provided by deposit money banks to GDP is used as indicator of FD and 0 otherwise | 0.14 | 0.35 |
| Private credit[a] | = 1 if private credit by deposit money banks and other financial intermediaries is used as indicator of FD and 0 otherwise | 0.10 | 0.30 |
| Bank | = 1 if bank ratio is used as indicator of FD and 0 otherwise | 0.06 | 0.24 |
| Private/dom. credit | = 1 if private credit/domestic credit is used as indicator of FD and 0 otherwise | 0.03 | 0.17 |
| Market capitalization | = 1 if stock market capitalization is used as indicator of FD and 0 otherwise | 0.06 | 0.23 |
| Market activity | = 1 if stock market activity is used as indicator of FD and 0 otherwise | 0.07 | 0.25 |
| Turnover ratio | = 1 if turnover ratio is used as indicator of FD and 0 otherwise | 0.09 | 0.29 |
| Other | = 1 if other indicator of FD is used as indicator of FD and 0 otherwise | 0.12 | 0.32 |
| Non-linear | = 1 if coefficient is derived from non-linear specification of financial development and 0 otherwise | 0.22 | 0.42 |
| Changes | = 1 if financial development is measured in changes rather than levels and 0 otherwise | 0.06 | 0.23 |
| Joint | = 1 if more than one financial development indicator is included in regression and 0 otherwise | 0.50 | 0.50 |
| *Estimation characteristics* | | | |
| OLS | = 1 if ordinary-least-squares estimator is used for estimation and 0 otherwise | 0.42 | 0.49 |
| IV | = 1 if instrumental-variables estimator is used for estimation and 0 otherwise | 0.17 | 0.37 |
| FE | = 1 if fixed-effects estimator is used for estimation and 0 otherwise | 0.08 | 0.27 |
| RE | = 1 if random-effects estimator is used for estimation and 0 otherwise | 0.02 | 0.13 |
| GMM (base category) | = 1 if GMM estimator is used for estimation and 0 otherwise | 0.30 | 0.46 |
| Endogeneity[b] | = 1 if the estimation method addresses endogeneity and 0 otherwise | 0.51 | 0.50 |
| *Conditioning variables characteristics* | | | |
| Regressors | The total number of explanatory variables included in the regression (excluding the constant term) | 7.97 | 3.77 |
| Macro. stability | = 1 if primary study controls for macroeconomic stability in conditioning data set and 0 otherwise | 0.71 | 0.45 |
| Pol. stability | = 1 if primary study controls for political stability and 0 otherwise | 0.13 | 0.34 |
| Trade | = 1 if primary study controls for effects of trade and 0 otherwise | 0.53 | 0.50 |
| Initial income | = 1 if primary study controls for level of initial income and 0 otherwise | 0.71 | 0.45 |
| Human capital | = 1 if primary study controls for level of human capital and 0 otherwise | 0.67 | 0.47 |
| Investment | = 1 if primary study controls for amount of investment (share of investment in GDP or the amount of foreign direct investment in GDP) and 0 otherwise | 0.30 | 0.46 |
| Fin. Crisis | = 1 if dummy variable for some indicators of financial fragility is included in estimation and 0 otherwise | 0.03 | 0.17 |
| Time dummy | = 1 if time dummies are included in estimation and 0 otherwise | 0.15 | 0.35 |
| *Publication characteristics* | | | |
| Journal impact factor | The recursive RePEc impact factor of the outlet as of July 2012 | 0.33 | 0.42 |
| Publication year | The year of publication (the mean is subtracted) | 0.00 | 1.05 |
| *Real factors: differences between time periods* | | | |
| 1960s | = 1 if data from 1960s are used and 0 otherwise | 0.35 | 0.48 |
| 1970s | = 1 if data from 1970s are used and 0 otherwise | 0.78 | 0.42 |
| 1980s (base category) | = 1 if data from 1980s are used and 0 otherwise | 0.94 | 0.24 |
| 1990s | = 1 if data from 1990s are used and 0 otherwise | 0.79 | 0.41 |

| Variable | Description | Mean | Std. dev. |
|---|---|---|---|
| 2000s | = 1 if data from twenty-first century are used and 0 otherwise | 0.50 | 0.50 |
| *Real factors: differences between regions* | | | |
| East Asia & Pacific (base category) | = 1 if countries from East Asia and Pacific are included in the sample and 0 otherwise | 0.75 | 0.43 |
| South Asia | = 1 if countries from South Asia are included in the sample and 0 otherwise | 0.70 | 0.46 |
| Asia | = 1 if Asian countries are included in the sample and 0 otherwise | 0.70 | 0.46 |
| Europe | = 1 if European countries are included in the sample and 0 otherwise | 0.70 | 0.46 |
| Latin America | = 1 if Latin American & Caribbean countries are included in the sample and 0 otherwise | 0.75 | 0.43 |
| MENA | = 1 if Middle East & North African countries are included in the sample and 0 otherwise | 0.72 | 0.45 |
| Sub-Saharan Africa | = 1 if Sub-Saharan African countries are included in the sample and 0 otherwise | 0.71 | 0.45 |
| Rest of the world | = 1 if rest of world (mainly high-income OECD countries) is included in the sample and 0 otherwise | 0.66 | 0.47 |

*Note: FD stands for financial development.*
*[a]Private credit by deposit money banks and other financial intermediaries to GDP was used as an indicator of financial activity along with private credit provided by deposit money banks to GDP.*
*[b]Primary studies address endogeneity by applying the general method of moments, the instrumental variable estimator, two-stage least squares or by estimating a lagged effect of financial development on economic growth.*

The variables reflecting differences in research design can be divided into four broad categories: differences in specification, data characteristics, estimation characteristics, and publication characteristics. Various measures that approximate the degree of financial development have been used in the empirical literature as discussed above. To account for the different measures, we construct several dummy variables based on the discussion in Section 2.2. Moreover, we introduce dummy variables to capture the definition of the dependent variable in equation (1). Researchers typically use GDP growth or per capita GDP growth measured in either real or nominal terms.

We construct moderator variables that capture the differences in the regressions included in the reported growth regressions. Our motivation for including these variables is that model uncertainty has been emphasized as a crucial aspect in estimating growth regressions (Levine and Renelt, 1992). We include variables that reflect the number of regressors in primary studies and dummy variables, such as *Macroeconomic stability*, *Political stability*, and *Financial crisis*, that correspond to the inclusion of important control variables.

In addition, we control for data characteristics, such as the number of countries included in the regressions, data frequency, and sample size. Time-series models usually use annual data, and studies with panel data commonly employ values averaged over five-year periods, whereas cross-country regressions often use values averaged over several decades. Beck and Levine (2004) find that using annual data rather than data averaged over five-year periods results in a breakdown of the relationship between financial development and economic growth. Some authors emphasize the importance of using low-frequency data to reduce the effect of business cycles and crises, and thus, they focus entirely on the long-run effects of growth (see Beck and Levine, 2004; Levine, 1999; among others). The dummy variable *Homogeneous* is used to assess whether mixing too heterogeneous countries may lead to systematically different estimates. We consider that the primary studies used a homogeneous sample of countries if a cross-country sample for a particular region is used (according to the definition of the World Bank: for example, Middle East and North Africa, or Latin America and Caribbean), if only developed or transition or developing countries are included, or if the focus of the primary study is a single country. For example, Ram (1999) points to structural heterogeneity across the countries pooled by King and Levine (1993).

As some estimation techniques used in the literature do not address the simultaneity bias in the finance–growth nexus, we control for different econometric methods employed in primary studies. In cross-sectional studies, some authors use the initial values of financial development and other explanatory variables in the regression to address the simultaneity bias (for example, King and Levine, 1993; Deidda and Fattouh, 2002; Rousseau and Wachtel, 2011). Other studies use the country's legal origin as an instrumental variable for financial development (for example, Levine, 1999; Levine et al., 2000). In addition, panel data techniques may be more successful in dealing with omitted variable bias.

We include journal impact factors to capture differences in quality not covered by the variables reflecting methodology. We use the recursive RePEc impact factor of the outlet where each study was published. While there are many ways to measure impact factors, we select the one from RePEc because it reflects the quality of citations and covers almost all economic journals.[21] We also include the variable *Year of publication,* for two reasons. First, we hypothesize that the perception of the importance of financial development in economic growth may have changed over time. If this is the case, results that are in accordance with the prevailing view may be more likely to be published. Second, the published pattern in the literature may also have changed because recent studies could have benefited from the application of new econometric

[21] Other recursive impact factors are available; for example, the SJR published by Elsevier and the Article Influence Index published by Thompson Reuters. We choose the RePEc impact factor because it covers much more economics journals and includes citations from working papers. Nevertheless, it should be noted that the RePEc ranking is still labelled as experimental, as many citations are missing (especially from Elsevier journals), and it also does not use a common sampling window for either the source publications or for the citing publications The recursive RePEc impact factor has been previously used in meta-analysis by, for example, Rusnak et al. (2013).

techniques, which consider simultaneity or omitted variable biases as well as unobserved country characteristics.

Financial development may have different growth effects in different regions and at different times. For example, Patrick (1966) and, more recently, Deidda and Fattouh (2002) suggest that the role of financial development in economic growth changes over the stages of economic development. Several studies find that the growth effect of financial sector development varies across countries (for instance, De Gregorio and Guidotti, 1995; Odedokun, 1996; Ram, 1999; Manning, 2003; Rousseau and Wachtel, 2011; Yu et al., 2012). To address the possibility that the finance–growth nexus may be heterogeneous across different geographic regions, we include regional dummies. To investigate the effect of finance on growth across different time periods, we construct dummy variables reflecting the following decades: *1960s*, *1970s*, *1990s*, and *2000s*, with the *1980s* as the base. We select the *1980s* as the base period to test the hypothesis of Rousseau and Wachtel (2011), who argue that the effect of financial development on economic growth has declined since the 1980s. **Table 5** presents the results of the multivariate meta-regression. The results suggest that heterogeneity in the estimated effects arises not only because of the differences in research design, but also because of real factors, such as differences between regions and time periods. The results of the meta-regression analysis with all potentially relevant moderator variables are listed in the third column of **Table 5**. The final specification in the rightmost column of that table is obtained by sequentially omitting the least significant moderator variables. We follow the general to specific modelling approach as it represents a common practice in meta-regression analysis for obtaining a parsimonious model that contains only the most important variables (see, for example, Doucouliagos and Stanley, 2009).[22] Based on the likelihood ratio test, we reject the null hypothesis of no between-study heterogeneity at the 1% level, which supports the use of the mixed-effects multilevel model rather than OLS. As a robustness check, however, we also estimate our regression model using OLS with standard errors clustered at the study level. The findings confirm our baseline results, even though the estimated standard errors are, for some variables, a bit larger.

[22] We note, however, that in light of recent advances in meta-analysis, instead of relying on general-to-specific strategy to report the results of a meta-regression analysis, researchers could rely on BMA techniques. In this way, in addition to reporting the full meta-regression results or results obtained by using only the most important variable found to be important for explaining the effect at hand, BMA has been increasingly used in meta-analysis conducted in the field of economics to account for model uncertainty (Raftery et al., 1997; Havranek and Sokolova, 2020). The BMA uses a weighted average over many specifications with different combinations of control variables, where weights given to each specification being proportional to goodness of fit and model parsimony (Steel, 2020). For application of BMA to the field of economics and finance, refer to Zigraiova and Havranek (2015).

The OLS results are presented in the online annex at *http://meta-analysis.cz/finance_growth*.

**Table 5: Explaining the Differences in the Estimates of the Finance-Growth Nexus**

| Moderator variables | | | All variables | Specific |
|---|---|---|---|---|
| Differences due to research design | Differences in dep. var. | Nominal GDP per capita | 0.041(0.064) | |
| | | Nominal GDP | 0.314***(0.071) | 0.242***(0.062) |
| | | Real GDP | 0.208***(0.072) | 0.157**(0.064) |
| | Data characteristics | No. of countries | -0.002***(0.000) | -0.002***(0.000) |
| | | No. of time units | 0.000(0.000) | |
| | | Sample size | -0.237***(0.024) | -0.237***(0.022) |
| | | Length | 0.012***(0.002) | 0.012***(0.002) |
| | | Log | -0.101**(0.043) | -0.069*(0.037) |
| | | Cross-section | 0.065**(0.032) | 0.070**(0.031) |
| | | Time series | 0.449***(0.158) | 0.408***(0.151) |
| | | Homogeneous | -0.037(0.024) | |
| | Measures of financial development | Financial activity | -0.029***(0.011) | -0.031***(0.010) |
| | | Private credit | 0.037**(0.015) | 0.037**(0.015) |
| | | Bank | 0.001(0.015) | |
| | | Private/dom. credit | -0.053**(0.024) | -0.051**(0.024) |
| | | Market capitalization | 0.128***(0.016) | 0.128***(0.016) |
| | | Market activity | 0.151***(0.014) | 0.148***(0.013) |
| | | Turnover ratio | 0.087***(0.015) | 0.087***(0.015) |
| | | Other | 0.077***(0.013) | 0.077***(0.013) |
| | | Non-linear | -0.006(0.010) | |
| | | Changes | 0.084(0.066) | |
| | | Joint | -0.044**(0.017) | -0.048***(0.016) |
| Differences due to research design | Estimation characteristics | OLS | 0.069*(0.038) | 0.028***(0.010) |
| | | IV | 0.002(0.030) | |
| | | FE | 0.040(0.037) | |
| | | RE | 0.050(0.040) | |
| | | Endogeneity | 0.032(0.039) | |
| | Conditioning variables | Regressors | -0.008**(0.003) | -0.006**(0.003) |
| | | Macro stability | 0.029(0.022) | |
| | | Pol. stability | 0.036(0.045) | |
| | | Trade | 0.013(0.020) | |
| | | Initial income | 0.188***(0.054) | 0.184***(0.049) |
| | | Human capital | 0.081**(0.036) | 0.092***(0.035) |
| | | Investment | -0.242***(0.052) | -0.225***(0.047) |
| | | Fin. Crisis | 0.232***(0.067) | 0.262***(0.061) |
| | | Time dummy | 0.046(0.035) | |
| | Publication characteristics | Journal impact factor | 0.109**(0.044) | 0.079*(0.042) |
| | | Publication year | 0.029***(0.006) | 0.022***(0.005) |
| Differences due to real factors | Differences between time periods | 1960s | -0.185***(0.035) | -0.144***(0.030) |
| | | 1970s | 0.153***(0.039) | 0.120***(0.036) |
| | | 1990s | -0.077*(0.046) | -0.118***(0.034) |
| | | 2000s | -0.069(0.043) | |
| | Differences between regions | South Asia | -0.013(0.041) | |
| | | Asia | 0.003(0.032) | |
| | | Europe | 0.132***(0.033) | 0.131***(0.020) |
| | | Latin America | 0.104***(0.031) | 0.108***(0.027) |
| | | MENA | 0.034(0.027) | 0.047*(0.025) |
| | | Sub-Saharan Africa | -0.091**(0.037) | -0.082***(0.027) |

| Moderator variables | | All variables | Specific |
|---|---|---|---|
| | Rest of the world | -0.032(0.032) | |
| | 1/SEr | 1.804***(0.151) | 1.805***(0.133) |
| | Constant | -8.032***(0.629) | -7.754***(0.587) |
| | Observations | 1334 | 1334 |
| | Studies | 67 | 67 |
| | Within-study correlation | 0.66 | 0.62 |

*Notes: Dependent variable: t-statistic of estimated coefficient related to financial development. Estimated by mixed-effects multilevel model. Standard errors in parentheses; ***,**,* denote significance at the 1%, 5%, and 10% level, respectively.*

Before turning to the discussion of our results concerning heterogeneity, it is worth noting that the coefficient controlling for publication bias in **Table 5** becomes large and statistically significant when study aspects (additionally to precision) are accounted for. This is puzzling, because our analysis in the previous section implies that estimates of the effect of finance on growth are little correlated with their standard errors. The likely explanation is that some aspects of data or methodology may be associated with publication bias, or small-sample and other biases.[23] Whatever is the source of the large constant reported in **Table 4**, it does not affect much our estimate of the effect of finance on growth; evaluated at sample means, it is on average still around 0.2 and thus close to the simple mean of partial correlation coefficients.

We identify several variables that significantly influence the reported effect of financial development on economic growth, and find that the effect varies across regions. For example, the effects seem to be greater in Latin America and Europe, but smaller in Sub-Saharan Africa, as compared to East Asia and Pacific. The different regional effects clearly show that it is not sensible to pool different regions together as the estimated impact of finance on growth is not stable across regions (i.e. primary studies should control for region and potentially the level of development in their estimations). The different regional effects also suggest that for countries at a lower stage of development (Sub-Saharan Africa and South Asia), other factors might be more important to focus on initially than trying to expand certain aspects of the financial sector (e.g. the stock market). It is worth noting, however, that the primary studies included in the meta-analysis did not consider measures of financial inclusion and the availability of data for less developed countries among the primary studies was limited, therefore more research is needed to derive relevant policy implications suited specifically for developing countries.[24] For example, a number of more recent studies

[23] Both moderator variables related to publication characteristics, namely, Journal impact factor and Publication year, are significant and positive. This finding suggests that studies published in journals with a higher impact factor report, on average, larger effects and that more recent studies report, on average, larger effects than earlier studies.

[24] It is worth noting that even the availability of data capturing the most widely used indicators of financial development are scare for developing countries. For example, even according to the at the time of finalising this thesis latest data contained in the Global Financial Development Database from October 2019, data on bank ratio is only available for 3 countries in SSA. Data is also very

relying on the newly available data in the Global Financial Inclusion Database support the positive relationship between financial inclusion and economic growth (e.g. Sethi and Acharya, 2018; Erlando et al., 2020).

Using the results of the specific regression reported in the last column of **Table 4**, we can compute the implied value of the partial correlation coefficient for each region. That is, we evaluate the estimated regression at sample means and plug in value 1 for the region in question and the value of 0 for all other regions. For our baseline category, East Asia, we get 0.13. The estimate rises to 0.26 for Europe and 0.23 for Latin America, but declines to 0.04 for Sub-Saharan Africa. Note that the region-specific estimates evaluated at sample means are imprecise, with standard errors around 0.65 in all cases. The differences in effects across regions are, however, statistically significant.

This finding suggests that the growth effects depend on the level of economic development, which is stressed by Rioja and Valev (2014), Ram (1999), Rousseau and Wachtel (2011), Manning (2014), and Yu et al. (2012), among others. In contrast, the results are not in accordance with De Gregorio and Guidotti (1995), who find that the impact of financial development on growth is negative for a panel of Latin American countries. Our results on Sub-Saharan Africa, conversely, give support to the previous research by Levine et al. (2000). It also seems that the growth effect of financial development declined in the 1990s compared to the 1980s, which is consistent with Rousseau and Wachtel (2011).

Our results suggest that the number of countries, as well as the sample size included in the analysis, matters for the reported results. Studies relying on cross-sectional and time-series data report, on average, larger effects than studies using panel data. The variable *Length,* which stands for the number of years in the time unit, is found to be positive and significant, which corresponds to the findings of Calderon and Liu (2003). That is, studies that examine longer time horizons generally report larger effects. This suggests that the effect of financial development is higher in the long-run.[25] Studies

scarce for the market capitalisation ratio (4 data points in SSA) and the market turnover ratio (3 data points in SSA), whereas metrics measuring financial inclusion, such as the share of population with a money account is readily available (GFDD, 2019). The latter could be used as a proxy for financial development when looking at less developed countries.

[25] We note that using averaged observations over longer time intervals has been commonly used among studies analysing the relationship between financial development and economic growth with data most frequently averaged over 5 years instead of using a higher frequency data (e.g. quarterly or annual). Data are averaged over a longer time horizon in order to abstract from business cycle fluctuations as noted by for example Beck and Levine (2004). The research in the field has generally focussed on evaluating long-term relationships between financial intermediaries, stock markets and economic growth, thus averaging data over longer time periods. An interesting finding supported by findings in this thesis is by e.g. Loyza and Ranciere (2006, p. 1069) who found that “a positive long-run relationship between financial intermediation and output growth can coexist with a negative short-run relationship”.

using the log of the dependent variable report, on average, smaller finance–growth effects than other studies.

The other important finding is that the proxy used to measure financial development matters, since this is found to be an important factor in explaining the heterogeneity in results. Specifications that use measures of stock market development, such as market capitalization, market activity, or turnover ratio, typically yield greater growth effects compared to financial depth, which we use as the base category. Therefore, our results suggest that the growth effects of stock markets are greater than that of financial intermediaries. In addition, we also estimate a regression model for which we use different measures of financial development and create only two dummy variables, one for studies examining stock market development and the other one for studies examining banking sector development. Our robustness checks show a positive coefficient of 0.06 for stock market studies and a negative coefficient of –0.09 for banking sector studies, both statistically significant at the 1% level. The issue of the importance of financial structure has received considerable attention in primary studies. For example, Demirguc-Kunt and Levine (1996), Levine (2002, 2003), and Beck and Levine (2004) show that it is the provision of financial services rather than financial structure that affects economic growth. On the other hand, Arestis et al. (2010) and Ergungor (2008) argue that financial structure matters.

Luintel et al. (2008) and Arestis et al. (2010) find that financial structure is irrelevant for growth only if cross-country heterogeneity is ignored. Once the panel econometric framework explicitly accounts for heterogeneity, financial structure gains importance. Ergungor (2008) shows that the effect of financial structure on economic growth depends on the level of inflexibility of judicial environments. If inflexibility is high, bank-based systems are more conducive to growth. Otherwise, stock markets are more supportive for growth. The results of Peia and Rozsbach (2013) also suggest that banks and stock markets influence economic growth differently.

Demirguc-Kunt et al. (2013) show that the effect of banks and stock markets on economic growth depends on the stage of economic development. The effect of bank development on economic growth decreases with economic development. On the other hand, the pattern for stock markets is opposite and the effect increases as the country develops. Therefore, the results suggest that there exists a certain optimal financial structure. In addition, Demirguc-Kunt et al. (2013) find that deviation from this optimal financial structure is costly in terms of economic growth. This is in line with the prediction of the theoretical model by Fecht et al. (2008), who show that stock markets may have greater effects on economic growth than banks.

Our results suggest that it is important to control for endogeneity when analysing the relationship between financial development and economic growth. Studies using OLS find, on average, larger effects than studies that account for endogeneity in some way - for example, using instrumental variables, panel data methods, or other more advanced techniques. Despite the fact that endogeneity is an important issue especially pervasive is the field of economics (Clemens and McKenzie, 2018), about half of the specifications obtained from primary studies did not attempt to address endogeneity issues, most frequently using GMM and instrumental variable estimator. Both moderator variables related to publication characteristics, namely, *Journal impact factor* and *Publication year*, are significant and positive. This finding suggests that studies published in journals with a higher impact factor report, on average, larger effects and that more recent studies report, on average, larger effects than earlier studies.

The reported estimates of the finance–growth relationship are sensitive to the set of conditioning variables included in the growth regressions, a finding that corroborates the findings of Levine and Renelt (1992). If primary studies account for the level of initial income, include a variable related to human capital, or control for financial fragility, they are likely to yield larger effects. On the other hand, specifications that control for the amount of investment in the economy tend to report lower effects. This result may be because the level of investment in the economy is a function of financial development.

The online annex includes additional regressions and sensitivity analysis. We re-estimate the funnel asymmetry test reported in **Table 3** using subsamples of coefficients reported for different regions and subsamples of different decades of data that are examined in the primary studies. The pattern of publication bias varies little across regions and time periods (we only get a statistically significant estimate of the extent of publication bias for studies using data from the 2000s). Concerning the puzzling negative (and sometimes even significant) estimates in our sample, which account for almost 20% of the data, we find that they are reported more often in recent periods, which might suggest that the increasing sophistication of financial systems increases the risks of adverse effects.

Furthermore, we re-estimate the multivariate meta-regression reported in **Table 5** using OLS instead of mixed effects and also include a non-weighted meta-regression.

For interpretation we prefer the weighted mixed effects presented in the main body of the paper, because they correct for heteroskedasticity and take into account within-study dependence of the estimates. The sensitivity checks provide less statistical significance for the estimated coefficients of several meta-regression variables. Nevertheless, focusing on the sensitivity checks would not change our main results; that is, the effect of estimation methods on reported coefficients, the importance of the choice of the measure of financial development, changes in the reported effect of financial development on growth in time, and heterogeneity in the reported effect across regions.

## 2.6. Conclusions

We perform a meta-regression analysis of studies analysing the importance of financial development for economic growth. We observe substantial heterogeneity in the reported estimates and find that only about half of them report a positive and statistically significant effect. Nevertheless, using meta-analysis methods, we show that the literature as whole documents a moderate, but statistically significant, relationship between financial development and economic growth. In addition, we subject the literature to several tests for publication bias and do not find strong evidence that researchers, referees, or editors demonstrate a preference for certain types of results.

After examining 67 studies that provide 1334 estimates in the field, we find that the heterogeneity in the reported effects is driven by both real factors and differences in research design. The finance–growth nexus varies across regions, which challenges the assumption of a common parameter used for heterogeneous countries in growth regressions. For example, we find that the growth effect of financial development is strong in European and Latin American countries but weaker in Sub-Saharan Africa. Our results also suggest that the beneficial effect of financial development decreased in the 1990s, but seems to have rebounded in the last decade to the level of the 1980s.

We find that how researchers measure financial development does play an important role. Measures based on stock markets are associated with greater growth effects than measures based on financial intermediaries. As a consequence, our results give support to the hypothesis that financial structure is important for the pace of economic development, as the contribution of stock markets to the growth process tends to be higher than that of other financial intermediaries. We note, however, that the primary studies included in the meta-analysis did not consider measures of financial inclusion and the availability of data for less developed countries among the primary studies was limited, therefore more research is needed to derive relevant policy implications suited specifically for developing countries.

With respect to the differences in research design, our meta-regression analysis provides evidence that the reported estimates of the finance–growth relationship depend on the set of control variables included in the growth regressions. Studies that control for the level of initial income, human capital, and financial fragility tend to report larger effects, which suggests that regression model uncertainty and omitted variable bias are important factors driving the estimated effect of financial development on growth.

In addition, our results show that addressing endogeneity is important for correct estimation and that studies that ignore endogeneity issues tend to exaggerate the size of the effect of financial development. The data frequency used in the estimation also influences the reported estimates. We find that studies that use averages of observations across longer periods (thus reducing the impact of the business cycle or short-term financial volatility on the estimates) and that use longer data samples tend to report greater effects of finance on growth.

**Acknowledgements**

We thank Chris Doucouliagos, Jarko Fidrmuc, James Laurenceson, Tomas Konecny, Oana Peia, Martin Strieborny, Borek Vasicek, and seminar participants at Charles University and the Czech National Bank for helpful comments. We thank the Czech National Bank for support. Horvath acknowledges support from the Czech Science Foundation (Grant No. 402/12/1993); Havranek acknowledges support from the Czech Science Foundation (Grant. No. P402/11/0948). An online annex providing the data set, additional results, and the list of studies included in the meta-analysis is available at http://meta-analysis.cz/finance_growth. Our views do not necessarily represent those of the Czech National Bank.

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# Chapter 3

# The Costs of Providing Access to Electricity in Selected Countries in Sub-Saharan Africa

**The results of this chapter were published as**: Valickova, P., Elms, N., 2021. The costs of providing access to electricity in selected countries in Sub-Saharan Africa and policy implications. Energy Policy 148. https://doi.org/10.1016/j.enpol.2020.111935.

**Abstract**: Access to reliable energy is recognised as a key driver of human and economic development. Despite this, today less than half of the population in Sub-Saharan Africa has access to electricity. Our analysis shows that at the current rate of progress in providing households with access, less than 60% of the population will have access to electricity by 2030. In view of the need to accelerate the rate at which electricity access is provided, we develop a detailed least-cost optimisation model to identify the incremental costs of providing access for the group of 12 countries in the Southern African Power Pool. Our analysis shows that achieving universal access by 2030 in the region, would lead to an incremental generation cost of between 5.2 and 11.4 US$2018 billion, depending on the consumption of newly connected households. This corresponds to an increase of system generation costs by 4–8% and the levelized incremental cost of supply to the customer of 108–116 US$2018 per megawatt hour.

This is lower than what a typical household pays for poor alternatives to electricity, such as kerosene for lighting, implying that policy makers should accelerate access.

**Keywords**: electricity access, power sector modelling, development, Sub-Saharan Africa

**JEL classification**: Q40, Q41, Q47, I3, O55

**Funding**: This work was supported by the Charles University Grant Agency (grant number 829 317) and H2020 Marie Skłodowska-Curie Actions (grant number 681 228).

# 3.1. Introduction

Access to reliable energy is recognised as a key driver of human and economic development, and a necessary condition for eradicating poverty and embarking on a path of inclusive economic growth (IEA, 2010; UN, 2017a; SE4ALL, 2017; Sarkodie and Adams, 2020). For example, access to modern lighting increases the useful hours of the day, enhances people's health, safety, financial inclusion and economic activity (Bhatia and Angelou, 2015). Despite its importance, 862 million people worldwide lacked access to electricity and 2.7 billion people lacked access to modern cooking solutions at the end of 2018 (IEA, 2019a).

These people are forced to rely on traditional energy sources such as solid fuels, kerosene and candles to meet their basic energy needs, sources that are associated with numerous problems and are detrimental not only to the environment but also to the health of those people (IFC, 2012; Kimemia et al., 2014). The number of premature deaths attributable to the lack of access to modern energy sources is estimated at 2.5 million per annum and is set to increase further unless significant action is taken (IEA, 2019a). Furthermore, these poor alternatives to electricity supply are often more expensive than electricity, especially when measured on the basis of cost per lumen-hours (Bhatia and Angelou, 2015). For example, Schnitzer et al. (2014) estimate that households spend around US$ 14 per month on kerosene, candles and mobile phone charging alone.

Promisingly, the global commitment towards universal and sustainable access to modern energy has strengthened over recent years. In 2015, the United Nations (UN) adopted the 2030 Agenda for Sustainable Development, featuring 17 Sustainable Development Goals (SDGs) to be achieved by 2030. These SDGs succeeded the Millennium Development Goals (MDGs) and unlike the MDGs explicitly included an energy related goal, SDG 7. The inclusion of energy among the SDGs was welcomed by energy practitioners, as having access to clean, reliable and affordable energy is often seen as vital for achieving other development goals. These include improvements in health (SDG 3), education (SDG 4), gender equality (SDG 5) and provision of water for agriculture and drinking (SDG6), all of which contribute to the overarching objective of poverty eradication (SDG 1) (OECD/IEA, 2017; McCollum et al., 2018; Nerini et al., 2017[27]). Access to modern energy services can also help with climate change mitigation efforts (SDG 13).

SDG 7 calls for ensuring affordable, reliable, sustainable and modern energy for everyone by 2030. Two indicators have been adopted to track progress towards achieving SDG 7.1:

- the share of population with access to electricity (indicator 7.1.1); and
- the share of population with primary reliance on clean fuels and technologies for cooking (indicator 7.1.2).

Focusing entirely on the former, the electricity access gap is particularly concerning in Sub-Saharan Africa (SSA), where only 45% of the population had access to electricity at the end of 2018 (IEA, 2019a). There is little doubt that progress remains too slow to achieve the target of universal access by 2030. Furthermore, this slow progress could be further aggravated by the COVID-19 pandemic (IEA, 2020a; IEA, 2020b). We analysed the recent rate of progress in providing electricity access among countries in SSA and, after accounting for population growth, at the current pace less than 60% of the population in SSA would have access to electricity by 2030 (**Table 7**), far below the SDG 7.1.1 target.

The obvious question is whether it would make economic sense to expand electricity access and at least get closer to achieving SDG 7.1.1, irrespective as to whether there are sufficient financial and other resources to achieve this. To answer this question, we quantify the wholesale generation costs of supplying the currently unelectrified households in the Southern region of SSA over the period 2019 to 2030, which coincides with the timing for the policy target entrenched in the SDGs. In addition, given that the speed at which electricity access is provided in the region would need to increase by a factor of 4.5 to meet the universal access target by 2030, we also consider a scenario in which a less stringent access target is achieved and a scenario in which the universal access target is delayed to 2040.

Specifically, we look at the costs of on-grid generation in accelerating the rate at which electricity access is provided in SAPP countries, whose power sectors are interconnected (Botswana, Democratic Republic of Congo, Lesotho, Mozambique, Namibia, South Africa, Swaziland, Zambia, and Zimbabwe) or are planned to be

[27] Nerini et al. (2017) identified synergies between 143 targets covering all SDGs and SDG 7. However, they also identified trade-offs between 65 targets and SDG 7, where nearly all trade-offs relate to the tension between the need for rapid action and the need for careful planning.

interconnected (Angola, Tanzania and Malawi). Furthermore, since several studies have shown the importance of trade in decreasing overall system costs (e.g. Bowen et al., 1999; Gnansounou et al., 2007; Castellano et al., 2015; Timilsina and Toman, 2016), we specifically model the electricity interconnection between countries and any resulting opportunities for trading electricity. We focus on generation costs because these are the largest cost component of the electricity sector, comprising about 60% of total costs (Castellano et al., 2015; EIA, 2019a) and because we consider the cost of electricity supply to those newly connected for a period of time, to 2030 or to 2040.

A multi-region power system expansion model is well suited to undertake this type of analysis. Today several energy modelling frameworks are available such as OSeMOSYS (Howells et al., 2011), MESSAGE (IAEA, 2016), MARKAL and TIMES (Loulou et al., 2005; Loulou, 2016). These are partial equilibrium modelling frameworks that allow the entire energy supply chain to be modelled, encompassing all the steps from resource extraction, through energy transformation, transport and distribution to final consumption of different energy related products and services demanded by energy consumers. The quantity of energy services supplied equals the quantity that consumers are willing to buy, adjusted for any losses during energy conversion and transportation. This supply-demand balance is present throughout the whole energy supply chain being modelled (Loulou, 2016). While these modelling frameworks are usually applied to the entire energy sector, they can also be applied to just one sector, such as the power sector. They rely on linear and mixed-integer programming to find a solution that minimises total discounted system costs of providing energy services or a solution that maximises the total discounted surplus (producer and consumer) over the entire planning horizon, within the bounds of the policy and resource constraints imposed. They assume competitive markets with perfect foresight, which means that all decisions are made in each modelled period with full knowledge of future events.[28]

These models have been used in a number of studies to conduct detailed energy and environmental analysis, over medium to long-term time horizons. With the exception of OSeMOSYS, they are nevertheless not easily accessible to new users (Howells et al.,

[28] Many other modelling frameworks of the energy sector are available, each with a different focus. For example, LEAP (Heaps, 2020) is primarily used for estimating emissions of relevant greenhouse gasses, short-lived climate pollutants and other air pollutants and how these can evolve under a range of scenarios over the long term horizon. Another interesting model, albeit not appropriate for our analysis when we are interested in understanding the long-term impact and investments needed to accelerate the rate at which access to electricity is provided, is ELMOD (A Model of the European Electricity Market), which allows a detailed representation of the power system in the short run, including a direct current (DC) load flow representation of transmission. See for example, Janda et al. (2017) or Malek et al. (2018) for application of ELMOD to Central Europe. Investments are, however, an exogenous input to ELMOD. We note that a dynamic version of ELMOD has been developed, dynELMOD (Gerbaulet and Lorenz, 2017) that includes endogenous decisions about investment in generation, storage and the transmission grid in 5-year intervals to 2050.

2011), and some require a commercial licence (e.g. the MARKAL/TIMES family of models). This is potentially why models such as MESSAGE and MARKAL/TIMES are used by large intergovernmental and international organisations, such as International Energy Agency (IEA), International Renewable Energy Agency (IRENA) or International Atomic Energy Agency (IAEA). While these partial equilibrium models can provide a more holistic picture of the whole energy system over a long time horizon, they tend to have a less detailed time representation. For example, MESSAGE uses 5 and 10 year time-steps to model up to 120 years (IIASA, 2020). Hence, one of the challenges with applying these modelling frameworks is the integration of long-term energy planning with short-term operation of power systems, which is a challenge discussed by Koltsaklis and Dagoumas (2018) in their overview of generation expansion planning models. Indeed, these modelling frameworks also tend to have a less detailed representation of the power sector and its operational characteristics (e.g. they generally do not explicitly include reserve margin or do not take into account ramp-rate constraints). We note, however that these models could be modified to include a more detailed representation of the operational aspects of the power sector. For example, IRENA modified MESSAGE to make it more suitable for analysing renewable energy technologies and included a 10% reserve margin on the system (IRENA, 2013).

Since these models cover the whole energy supply chain, their scope extends beyond purely energy issues, and are suitable for the analysis of environmental questions and related policies. For example, TIMES explicitly includes a climate module that allows representation of all energy related greenhouse gas emissions and ambient air pollutants throughout the supply chain (e.g. $CO_2$ emission reduction targets can be set). As noted by Loulou and Labriet (2008), this can be especially relevant for global representations of TIMES, such as TIAM (Times Integrated Assessment Model). TIAM looks at long term horizon (100 years) so that the long-term nature of climate related issues can be evaluated (Loulou and Labriet, 2008).

Some of these energy system models have been adapted and applied to the African electricity system. Specifically:

- IRENA developed SPLAT (The System Planning Test) model for Southern Africa. The SPLAT model was developed using MESSAGE modelling platform and builds on power system optimisation model developed by IAEA (IAEA, 2011) to which IRENA added additional constraints to better analyse the potential for development of renewable energy sources in the region and to take into account generation adequacy (IRENA, 2013). The SPLAT model developed by IRENA covers all the SAPP countries. The model assesses investment needs to meet grid and off-grid demand including endogenous decisions as to interconnector investments and national transmission and distribution infrastructure that is required to meet the demand of different types of electricity consumer (industrial, commercial, urban residential and rural residential). However, they represent demand by only 10 steps each year, which we view as a limitation of their model.

- Taliotis et al. (2016) relied on the OSeMOSYS modelling framework to develop TEMBA (The Electricity Model Base for Africa). TEMBA was applied to study the least-cost supply options, including the effect of electricity trade on system costs, in Africa. While the study and the TEMBA model cover 47 countries in Africa, the temporal resolution is limited as it models only 4 periods each year (summer and winter, night and day), which is an important limitation of the model as noted by the authors (Taliotis et al., 2016). While adding to the computational time, a greater temporal resolution is vital for a better understanding of the potential for trade between countries with different demand patterns. Relying on low temporal resolution has also been shown to lead to an overestimation of the uptake of variable renewable energy (VRE) and less flexible baseload technologies (Poncelet et al., 2016). Another limitation of TEMBA is that it does not explicitly include a reserve margin (Pappis et al., 2019), which would tend to understate the need for generation capacity.
- Energy Research Centre (ERC) of South Africa relied on TIMES to develop SATIM (South African TIMES model). This model is a least-cost optimisation that considers demand for electricity and demand for liquid fuels and other energy resources and how these affect the choice of fuels and technologies within the electricity sector and vice versa. The demand for these different energy services is closely linked to demand drivers such as GDP and population, and is thus endogenously determined by the model (Ireland and Burton, 2018). The modelling framework is also geared towards modelling long-term horizons since the system is optimised on a five year basis and does not include certain operational constraints on the power sector (ERC, 2017; Merven et al., 2017).

For a comprehensive overview of energy planning models, we refer the reader to Koltsaklis and Dagoumas (2018), who provide an overview of different generation expansion planning methodologies, with a focus on new challenges for expansion planning, and Ringkjøb et al. (2018) who presents a thorough review of 75 modelling tools for analysing energy and electricity systems. For their implementation in the context of SSA, we refer the reader to Trotter et al. (2017), who categorise 306 articles on quantitative and qualitative electricity planning in SSA according to various dimensions.[29]

While the modelling frameworks discussed above could have been potentially adapted to fit our analysis by applying a more detailed representation of time, adding constraints regarding reserve margins, and similar, we developed a detailed least-cost generation despatch and investment model as part of this study that we use to evaluate the incremental costs of achieving different electricity access targets for the twelve countries in SAPP. This is also the case since we are interested in a shorter time horizon (mainly up to 2030 with some calculations going up to 2040) and relatively detailed representation of the power sector. The innovation of our work should be viewed as the specific application of the model, looking at generation options in the SAPP as a way of lowering the affordability barrier to providing electricity access in the region and to provide specific policy recommendations. However, we emphasise that similar modelling frameworks are available and researchers familiar with those frameworks could rely on these and adapt them so that similar questions as asked in this research could be explored.

Several studies have assessed the cost of expanding access to electricity. Their methodologies and underlying assumptions vary greatly, according to their geographic scope, temporal resolution, time horizon, representation of generation technologies and their costs, assumptions about future fuel prices, representation of electricity demand and complexity of the analysis, among other aspects.

Some studies take a simple approach and do not rely on power system optimisation models. For example, Bazilian et al. (2012) and Bazilian et al. (2014) estimate the costs of achieving universal access using a simple heuristic based on the number of people that need to be connected and assumptions around their consumption level, and simple

[29] Least-cost electrification planning models are a separate class of models that focus on the least cost choice of technology to provide access, i.e. optimal choice between the main grid, mini grid and standalone system solutions. As is the case with Nereni et al. (2016) and Dagnachew et al. (2017), these models typically take the cost of main grid-based generation as an exogenous input that is invariant with the number of customers connecting to the main grid or their consumption.

heuristics to determine the generation mix required to meet demand. Based on this they derive the levelised cost of generation, as part of the overall levelised cost of supply. This approach, as noted by the authors, suffers from several simplifications including the inability to optimise the generation mix going forward.

Other studies rely on more formal power system modelling. For the SSA region, to the best of our knowledge, the most comprehensive studies include Rosnes and Vennemo (2012) and Castellano et al. (2015), that estimated the required investments in the power sector to meet the growing demand for electricity in SSA over the planning horizon. However, Rosner and Vennemo (2012) looked at the costs of supply over the period 2006 and 2015 only, with a focus on the overall costs of serving the growing demand for electricity. They did consider two access scenarios, a constant access scenario in which access rates were kept at their 2005 levels and a scenario in which stated national access targets are met, both of which are significantly below what is needed to extend electricity to the whole population in SSA. The study by Castellano et al. (2015) is more recent and focusses on the overall costs of supply in SSA, in which they relied on a heuristic approach to generation investment and despatch assuming a single access rate of 80% to be achieved by 2040.

Another study, by Spalding-Fecher et al. (2017), estimates the forward-looking cost of generation in the Southern African Power Pool (SAPP) region to 2070 by building demand from the bottom up, including making different assumptions about future access, and using a simulation model of generation investment and operations. A limitation of their model is that annual electricity trade flows are an exogenous input to the model, and the flows do not dynamically adjust with changes to demand and supply in each country and its neighbours. We see this as an important limitation for the type of analysis we are undertaking. More recently, SAPP Pool Plan (2017) relied on power system modelling to develop a regional power system plan over the period to 2040, but did not focus on the cost of providing a given level of access.

To the best of our knowledge no study assesses the incremental costs of meeting different electricity access targets building on detailed country-by-country supply and demand data for the group of 12 countries in the SAPP, while allowing transmission flows between countries to dynamically adjust so as to reduce supply costs. Therefore, our aim is to bridge this gap and to support discussion about the economic cost of providing access relative to the importance of electricity access in facilitating economic and human development. Our analysis also takes a fresh look at the costs of providing access in the region, taking into account recent developments in the power sector, including the shift in competitiveness of different generation technologies and available interconnection among the SAPP countries as of today, as well as the planned interconnection of Angola, Malawi and Tanzania.

Our planning model assumes a competitive market with perfect foresight and efficient use of assets such as power stations and electricity interconnectors between countries. The term “efficient” is central to our analysis and is used frequently in the remainder of this thesis. When we use the term efficient in the context of investing in or using an asset it means that rational decisions are taken based on forward looking economic costs, i.e. only those costs affected by the decision. In practice this means an investment is made only if the developer is able to recover its investment and operating costs and an asset is used only if it is profitable to do so. For an interconnector, this means electricity is sent through the interconnector whenever the percentage difference in wholesale electricity prices between the two interconnected countries is greater than the percentage losses on the interconnector. However, when the price difference is less, there is no flow. Wholesale price here refers to the shadow price on the demand supply balance equation for each country in the model, that is, the incremental cost of meeting a small increment of demand in an hour.

In the remainder of this chapter, we first review recent progress in increasing electricity access in SSA and assess the resulting achieved access rate in 2030 under the current rate of progress. Since most countries under the current rate of progress struggle to significantly increase the share of population with access to electricity, we estimate the additional level of effort required to accelerate the rate at which electricity access is provided and ultimately to achieve universal access. Second, we present scenarios for electricity demand and its development over time, including the incremental demand stemming from new connections. This is followed by an overview of the different technological solutions available to tackle this challenge and a description of the least-cost optimisation model developed as part of this study to estimate the incremental cost of providing access. Lastly, we present the results of our analysis and compare them to the current literature. In annexes to this thesis, we set out the wide range of power system data used in the least-cost optimisation model and describe mathematically the optimisation model used to derive our results.

## 3.2. Electricity Access Gap and its Outlook for SSA in 2030

Today there is no internationally recognised definition of electricity access. Nonetheless, there is a common understanding that for electricity access to be meaningful, it must be adequate in quantity, available when needed, of good quality, reliable, convenient, affordable, legal, healthy and safe. This understanding was conceptualized in Beyond Connections: Energy Access Redefined, which proposed a multi-tier framework for defining and measuring access to energy (Bhatia and Angelou, 2015), building on work done by others, including Practical Action (2010), Nussbaumer et al. (2012) and Nussbaumer et al. (2013). This framework underlines the importance that the access challenge does not end by providing an electricity connection. In fact, it has been shown that the share of households with reliable access is low in many countries in SSA (e.g. Blimpo and Cosgrove-Davies, 2019) and that electricity is unaffordable for many even if only a basic subsistence level of consumption of 30 kWh per month per household is considered (IEA, IRENA, UNSD, WB, WHO, 2019).

Despite this, measuring energy access in a comprehensive manner remains a challenge and binary metrics remain widely used, although they do not allow electricity access to be measured in a comprehensive way (Pelz et al., 2018). In this way, SDG indicator 7.1.1. uses a binary metric, which is the proportion of the population with access to electricity and where access is considered only if the primary source of lighting is the local electricity provider, solar systems, mini grids and stand-alone systems (IAEG-SDGs, 2020). Similarly, the International Energy Agency's (IEA) electricity access database uses a binary measure of access: i) those with a grid, mini-grid or off-grid connection of sufficient capacity to provide a basic bundle of energy services, and ii) those that do not have such a connection (IEA, 2020c).

In our analysis we relied on IEA's electricity access database which provides a comprehensive time series of annual access data by country from the year 2000. We note, however, that it is likely that the access data currently available understate the electricity access gap that needs to be bridged to meet the SDG 7 for electricity access, especially when aspects such as security of supply and affordability are considered.[30] In our analysis we relied on data contained in the 2019 World Energy Outlook and the underlying

[30] For example, Blimpo and Cosgrove-Davies (2019) note that some households, despite being connected to the main grid, report never having received power.

electricity access database by the IEA, which reports data on national, urban and rural electrification rates (IEA, 2019a). According to the IEA's binary metric, 860 million people were without access to electricity worldwide at the end of 2018 (IEA, 2019a). While progress on increasing electricity access rates has been made across all regions since the start of the new millennium, progress has been uneven. Developing Asia has been particularly successful in providing access, where the population share with access to electricity climbed from 67% in 2000 to 94% in 2018, despite a significant population increase. In contrast, the progress made in SSA has been slow. With an electricity access rate of 45% at the end of 2018, SSA remains the region with the lowest share of the population with access to electricity, lagging all other regions by close to 50 percentage points or more (IEA, 2019a).

Somehow reassuring that this access gap could be closed is the fact that in recent years we have witnessed an upward trend in the rate at which people are gaining access to electricity in SSA. A closer look at data on electricity access in SSA suggests that while at the beginning of this millennium, on average 10 million people were gaining access to electricity each year, this rate more than tripled to 38 million per annum over the period from 2013 to 2016. This acceleration meant that the absolute number of people without access in SSA began to decrease for the first time. However, according to the most recent data, the number of people gaining access each year fell to about 33 million between 2016 and 2018 (**Table 6**).

**Table 6: Electricity access in SSA and its development (2000–2018)**

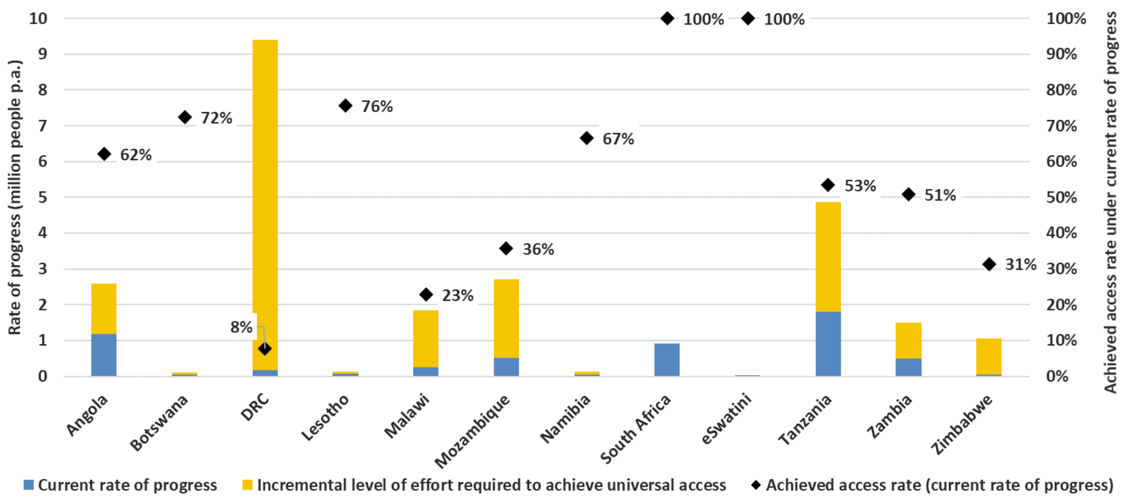
| Year | 2000 | 2005 | 2010 | 2013 | 2016 | 2018 |
|---|---|---|---|---|---|---|
| Population (million) | 665 | 759 | 869 | 943 | 1,023 | 1,078 |
| Electrification rate (%) | 24% | 28% | 33% | 32% | 42% | 45% |
| Population with access (million) | 160 | 211 | 283 | 309 | 423 | 490 |
| Population without access (million) | 506 | 548 | 586 | 634 | 600 | 589 |
| Change in population (million p.a.) | n/a | 19 | 22 | 25 | 26 | 28 |
| Change in population with access (million p.a.) | n/a | 10 | 14 | 8 | 38 | 33 |
| Change in population without access (million p.a.) | n/a | 8 | 8 | 16 | -11 | -6 |

*Source: Authors based on IEA (2019a), IEA (2018), IEA (2017), IEA (2015), IEA (2011) and the WDI (2019).*
*Note: Changes are calculated as the average change per annum between two adjacent columns of this table.*

If the current rate of progress in electrifying households in SSA continues, SDG 7 will not be met. According to the World Development Indicators, SSA will have a population of 1.45 billion in 2030. Hence, continuing to connect about 33 million people per year, which falls to 27.2 million once we assume that the rate of new connections of those countries forecast to achieve universal access before the SDG target year equals their net increase in population, less than 60% of the SSA population would have gained access to electricity by 2030. And, even if the higher 2013 to 2016 average rate of new connections were maintained, this would increase the achieved electricity access rate only marginally, by about two percentage points in 2030. This analysis shows that under the current rate of progress, SSA would fail to meet SDG 7.1.1 by a large margin and around 600 million people would still rely on more polluting and inadequate alternatives to electricity in 2030 (country details are provided in **Annex 2**).

The situation is even worse in the SAPP region. With a population weighted average electricity access rate of 39% as at the end of 2018, SAPP lags behind SSA's 45% access rate. Furthermore, if South Africa (SA) as a clear regional outlier both in terms of the current electrification rate and wealth is excluded, the access rate in the SAPP region falls to 27%, even further behind SSA's weighted average. Under the current rate of progress, the weighted average access rate in SAPP would increase only marginally from 39% to about 45% by 2030. Furthermore, if SA is excluded, the weighted average realised access rate in SAPP would increase from 27% as at the end of 2018 to only 35% in 2030. Our analysis suggests that among SAPP countries, only SA and eSwatini are well on track to achieving universal access to electricity by 2030 under the current rate of progress, with the other countries missing the SDG 7.1.1 target by a considerable margin (**Figure 2**).

**Figure 2: Current versus required rate of progress to achieve universal access by 2030**




*Source: Authors based on IEA (2019a), IEA (2018), IEA (2017), IEA (2015) and the WDI (2019).*

In other words, we estimate that the current rate of connections would need to increase on average by a factor of 5.2 among the SAPP countries, excluding SA, to achieve universal access by 2030. Furthermore, shifting the access target to 2040 would not help much due to the net population increase in the region. In SAPP, the increase in the level of effort required to significantly increase access to electricity is above the average increase in effort required across SSA as a whole. Current electrification rates, recent rate of progress and achieved access rate by 2030 and 2040 under the current rate of progress is summarised in **Table 7**.

**Table 7 Electrification rates achieved under the current rate of progress**

| Region | SSA | SAPP | SAPP excluding SA |
|---|---|---|---|
| Current electrification rate (population w/a) | 45% | 39% | 27% |
| Number of people without access (2018) | 590 | 193 | 190 |
| Net pop. increase 2018 – 2040 (million p.a.) | 33 | 10 | 9.4 |
| Population forecast in 2030 (million) | 1,455 | 427 | 361 |
| Population forecast in 2040 (million) | 1,815 | 536 | 465 |
| Current rate of connection (million people p.a.) | 27.2 | 5.6 | 4.7 |
| ***Achieved access rate (2030)*** | **56%** | **45%** | **35%** |
| ***Achieved access rate (2040)*** | **59%** | **45%** | **37%** |
| *Rate of connection required to achieve universal access by 2030 (million people p.a.)* | *80.6* | *25.3* | *24.4* |
| *Required rate of connection to achieve universal access by 2030 / current rate of connection* | *3.0* | *4.5* | *5.2* |

*Source: Authors based on IEA (2019a), IEA (2018), IEA (2017), IEA (2015) and WDI (2019).*

## 3.3. Different Technological Solutions to Bridge the Access Gap

Traditionally, electricity access has been provided by national utilities through new grid connections, predominantly supplied with power generated from fossil fuels and large hydro power plants. This was even the case for most of those who gained access in the period from 2000 to 2016 (OECD/IEA, 2017). However, new innovations and declining costs of renewable generation are rapidly transforming the market, with mini-grids and standalone systems gaining in importance (IRENA, 2019b).

There is little doubt that to significantly increase electricity access in SSA and serve the growing demand, densification and expansion of the existing grid, as well as off-grid solutions (mini-grids and standalone systems) are needed (Doll and Pachauri, 2010; Chaurey et al., 2012; Palit and Bandyopadhyay, 2016; Zeyringer et al, 2015; Dagnachew et al, 2017; Moner-Girona, 2017). The most cost-effective solution will be different for each area or settlement and will depend on many characteristics, such as distance from the main grid, demographics, size and density of population clusters, terrain, consumption patterns of end users, and the relative costs of different technologies and their future development (Nereni et al., 2016; Dagnachew et al., 2017; Ciller and Lumbreras, 2020).

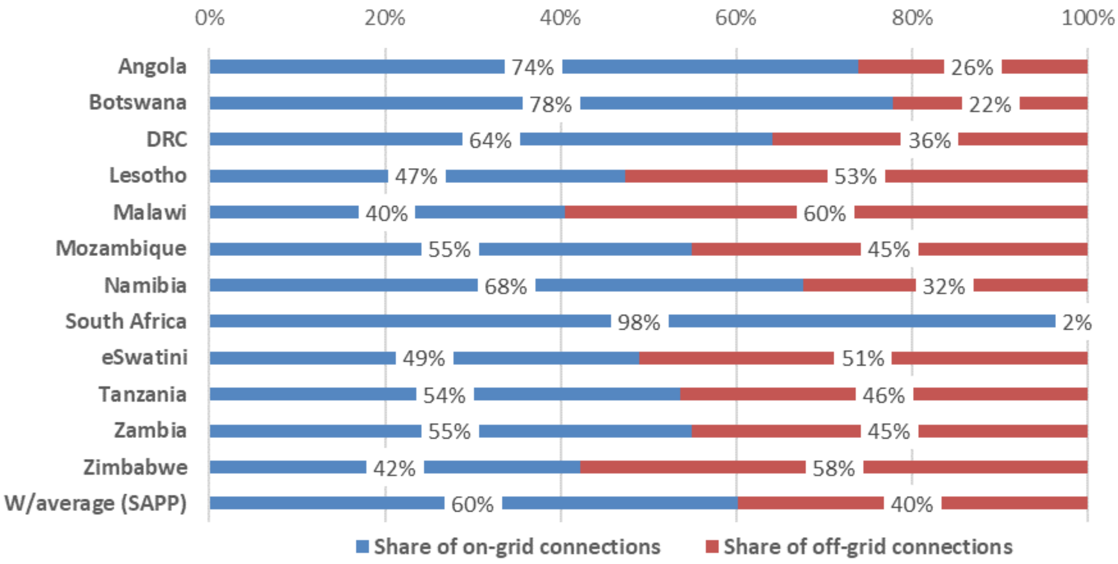
More research, and particularly detailed geospatial analysis, is needed to understand whether off-grid solutions or extension and densification of the grid is more appropriate for each country or region, taking account of the specific circumstances of each. The electricity market has witnessed an important reduction in costs, especially in the last decade, of both small off-grid and distributed generation technologies, as well as a substantial reduction in the costs of large utility-scale renewable technologies. This has created significant uncertainty as to which technology is most appropriate today and in future for providing reliable, affordable and clean power to currently unelectrified households, particularly for rural households. Furthermore, the appropriate technical solution for connecting currently unelectrified households also depends on the socio-economic justification for electrification, government plans and policy decisions, and considerations as to the level of service that should be provided. For example, Heynen et al. (2019) note that the government in India remained committed to providing on-grid solutions in most cases “ostensibly for political reasons” despite the benefits of an off-grid solution in a number of settings.

While a grid connection can deliver the highest power and the ability to connect more appliances than an off-grid connection, hence allowing consumers to use electricity for a wider range of services, a grid connection is often associated with high upfront connection costs that can significantly impact the demand for a grid connection (Lee et al., 2016; Lee et al., 2019). Grid extension and densification tends to be the most cost-effective solution in areas with a high population density (i.e. urban and peri-urban areas), whereas off-grid solutions can represent a cheaper alternative in areas that are currently too far to be reached by the main grid and for households with low income and low consumption.

In our analysis, we follow OECD/IEA (2017) and assume that a grid connection constitutes the least-cost means of access for all customers in urban areas and for 30% of households in rural areas, i.e. off-grid solutions are the least-cost option for 70% of those who gain access in rural areas. A similar approach has been applied by Rosnes and Vennemo (2012), and take account of research confirming that off-grid solutions are vital for extending access to electricity in rural areas (IEA, 2019a). Following this approach, we estimate that on average 60% of the population that gains access in SAPP would do so through grid extensions and 40% through off-grid solutions, under the scenario whereby universal access is reached by 2030.

Since each country has a different starting point for the number of people to be electrified in urban and rural areas and different future net population growth rates, each country has a different on-grid versus off-grid share of new connections required to meet any given access rate target. Under the scenario whereby universal access is achieved by 2030, the highest share of new on-grid connections would be in South Africa (98%), where the number of people living in rural areas is forecast to decrease, and the lowest share of new on-grid connections in Malawi (40%), Zimbabwe (42%) and Lesotho (47%), closely reflecting the relatively low current and future urbanisation rate and the relatively low rural access rate today (**Figure 3**).

**Figure 3: Share on-grid and off-grid connections in new household connections**




*Source: Authors based on OECD/IEA (2017), IEA (2019a) and WDI (2019).*
*Note: As we consider different scenarios for electricity assess rates to be achieved, this also affects the resulting number of people to be supplied by on-grid versus off-grid solutions. Higher urbanisation rates in later years mean that the share of grid connections in households newly gaining access would increase to 67% under the target year of 2040.*

We also assess a sensitivity whereby only 80% of all new connections in urban areas and 20% of households in rural areas are grid connected, which reduces the demand to be met by grid connected generation. We run this sensitivity since a number of studies have shown that on-grid electrification rates remain low even in areas with high population density and even once the grid has been extended to the area (e.g. Blimpo and Postepska, 2017; Blimpo and Cosgrove-Davies, 2019; Lee et al., 2016), and therefore the proportion of households connecting to the grid may be lower than we have assumed. Under this sensitivity, the share of on-grid access in the new connections decreases from 60% to 46% under the universal access target to be achieved by 2030.

## 3.4. Current and Incremental Demand for Electricity

Sound demand forecasting is essential for efficient power sector planning and development. The most comprehensive demand forecast for the SAPP region undertaken to date is, to our knowledge, available in the SAPP Pool Plan (2017). This is a detailed bottom-up demand forecast for the period 2017-2040 for each of the 12 SAPP countries built on forecasts supplied by the respective electricity utilities. The demand forecast is based on key demand drivers such as assumed economic growth, the respective growth rate of the various sectors of the economy, socio-economic parameters, the assumed number of new customers connected to the main grid, when this information was available, and the assumed consumption patterns of both existing and newly connected customers. The electricity demand forecast projects a 3.8% compounded annual growth rate (CAGR) in sent-out demand for the region over the period 2018 to 2030 and a CAGR of 3.5% in sent-out demand over the period 2018 to 2040. However, we note that the accuracy of the forecast seems to vary by country.[31]

In our analysis we model demand for electricity of each country individually. That is, for each of the 12 countries, demand is described in terms of sales, customer demand (i.e. electricity consumed by residential and non-residential sectors of the economy including suppressed demand when available), gross demand (i.e. demand that needs to be met by supply to the transmission network, also referred to as sent-out energy), peak demand (i.e. the annual maximum level of demand that needs to be met by supply to the transmission network) and a load curve (i.e. demand shape describing hourly demand within a year). Demand is defined exogenously to the generation optimisation model and the three demand inputs to the optimisation model are gross demand and peak demand for each country and each year, and a standard chronological hourly load curve which we flex to meet gross demand and peak demand in each country and each year.

[31] Today we can observe considerable differences between the SAPP forecast and actual data as reported by utilities for some of the countries, with actual demand being generally lower than forecast. For example, SAPP Pool Plan (2017) reports on-grid sales including estimates of suppressed demand in Botswana of 3,686 GWh in 2016. Actual sales were 3,495 GWh in 2016 (BPC, 2019), suggesting suppressed demand of about 207 GWh. Nevertheless, it is clear that the SAPP Pool Plan demand forecast is too high for 2018, only the second year of its forecast horizon. This can be seen by a simple comparison of actual electricity sent-out to meet domestic demand reported by the national utility of 3,920 GWh (BPC, 2019) and the SAPP Pool Plan (2017) forecast of 4,479 GWh, while unserved demand remained largely unchanged.

### 3.4.1. Current Level of Demand

To derive the current (2018) level of sent-out demand, we relied on actual demand data based on information contained in the annual reports of utilities, demand data of the International Energy Agency (IEA, 2019b), SAPP annual report (SAPP, 2018) and grid master plans (Norconsult et al., 2017; JICA, 2018a; JICA, 2018b; SA IRP, 2019). Since such data were available only for Botswana, Lesotho, Malawi, Namibia, South Africa, eSwatini, Tanzania Zambia and Zimbabwe, for the remaining countries (i.e. Angola, DRC and Mozambique) we relied on the forecast 2018 data contained in the SAPP Pool Plan (2017). When deriving the current level of end-user demand, we start with invoiced consumption, which we adjust upwards by the level of commercial or non-technical losses specific to each country to derive electricity consumed by customers, including estimates of suppressed demand, when available. We call this customer demand. To derive gross demand, we adjust customer demand upwards by the level of technical losses on the transmission and distribution networks.[32]

As noted, our customer demand and gross demand include suppressed demand (energy unserved), when relevant and when data was available.[33] Among countries in SSA, suppressed demand can be a considerable share of overall demand with some studies estimating it to amount to 6–13% of generation (Eberhald et al., 2011) and varying considerably over time depending on several factors. In 2018, the utilities in SAPP generally did not resort to load shedding and therefore the amount of any unserved demand in that year is expected to be low. Hence, we do not attempt to estimate suppressed demand for 2018, which is the base year for our demand forecast, unless specifically provided in the utilities' annual reports or considered in the SAPP Pool Plan (2017).[34] We note, however, that this would have been significantly different had our base year been 2019, when some countries in SAPP experienced severe power shortfalls. For example, in Zimbabwe power outages in 2019 lasted for up to 18 hours per day, largely because of low water levels at Kariba dam and deteriorating thermal generation assets (Hill, 2019). Eskom, the national utility of South Africa, resorted to stage 6 load

[32] In the power sector, losses are composed of technical and commercial losses, together comprising transmission and distribution (T&D) losses. The level of T&D losses varies considerably across countries and is generally low at around 6–9% in high income countries, and high in low income countries averaging 17%, with some countries reporting losses of over 25% of sent-out electricity (OECD/IEA, 2018). In practice, it is difficult to split technical losses from overall transmission and distribution losses. In our analysis we have assumed technical losses to be 10% of sent-out generation, unless otherwise specified in utility annual reports.

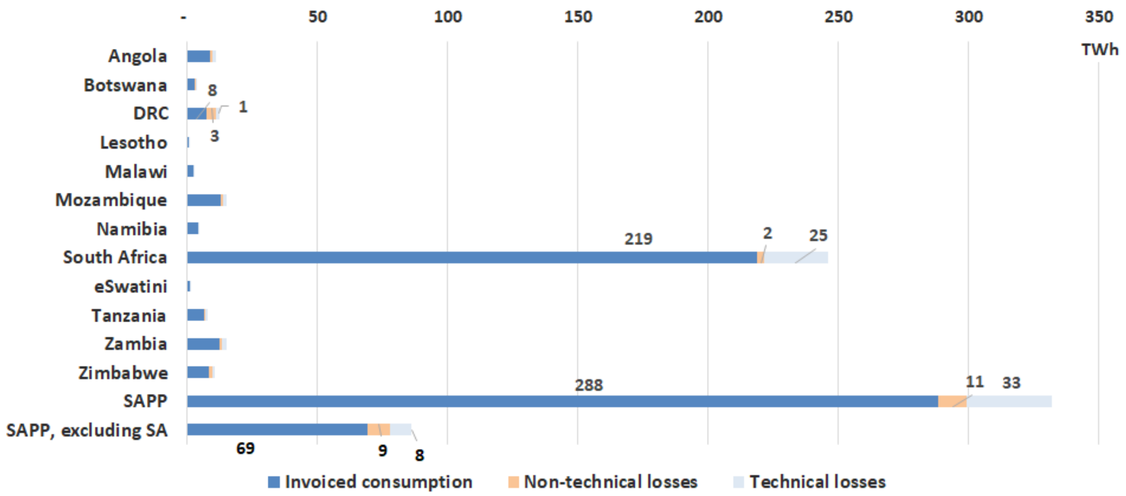
[33] Unserved energy is the amount of end-customer demand (measured as the amount of energy), that is unmet due to insufficient available generation capacity or constraints on transmission or distribution. Unserved energy can be a result of both planned and unplanned outages, with the former usually referred to as load shedding. Energy unserved is difficult to estimate but can be significant affecting the quality of electricity supplies from the grid.

[34] SAPP Pool Plan (2017) takes estimates of suppressed demand into account although we note that suppressed demand is not isolated in their forecast and, therefore, we do not know the level of suppressed demand considered.

shedding with 6000 MW of load shed in December 2019 (Eskom, 2019). Unreliable supply also leads to some customers switching to off-grid generation technologies and auto-generation. For example, according to the limited data available in World Bank Enterprise Surveys (2019), firms relied on back-up generation 26% of the time in Lesotho, 29% in Swaziland and 19% in Zimbabwe in 2016. It is possible that these estimates understate the proportion of time that a typical customer experiences an outage on the same network since using back-up generators is costly (IFC, 2019).

Based on this approach, we derive the overall level of customer demand for the SAPP region of close to 300 TWh in 2018. This level of customer demand reflects the non-technical losses estimated at 4% of consumption across the 12 countries (or 11% excluding SA). The current (2018) level of demand reflects the demand of existing customers, including both the residential and non-residential sectors of the economy. By adjusting this level of demand for technical losses estimated at 10% of sent-out energy, we derive gross demand of 332 TWh. SA has the highest share of this demand (246 TWh), with the remaining 11 countries having gross demand of only 86 TWh in total (26% of demand), despite representing over 80% of the population among the SAPP countries. Current level of electricity consumption and sent-out demand is summarised in **Figure 4**.

**Figure 4: Current level of consumption and sent-out demand (2018)**




*Source: Authors based on SAPP Pool Plan (2017), Norconsult et al. (2017), JICA (2018a), JICA (2018b), SA IRP (2019), IEA (2019b), Rocky Mountain Institute (2019) and utilities' annual reports.*

*Note: Consumption in each country is end-user consumption consisting of the amount of electricity billed by the utility in that year plus non-technical losses on the system. To derive the level of non-technical losses we relied on utilities' annual reports and compiled the level of overall transmission and distribution (T&D) losses on the system and assumed that technical losses are 10% of energy sent-out across all countries with the exception of: i) Mozambique, where Mozal, the aluminium smelter, represents a large proportion of demand and is connected to the transmission network and hence Mozambique has lower average technical losses estimated at 7.3% in 2018; and ii) eSwatini, where according to the annual report by the utility the level of technical losses was 12.09% of sent-out in 2018 (EEC, 2018). Technical losses relate to electricity lost in transmission, transformation and distribution networks as a result of power being transported from the point of generation to the point of consumption. Non-technical losses are then calculated for each country from the level of overall T&D losses and the assumed level of technical losses as 1-((1-overall T&D losses)/(1-technical losses)). Detailed country-level data are provided in **Annex 6**.*

For electricity demand projections, we use a 4% annual growth rate for non-residential demand and a 2% annual growth rate for residential demand of existing customers across all countries[35], with the exception of South Africa. For South Africa, we used an average annual electricity demand growth of 1.8% for both the residential and non-residential sectors of the economy following SA IRP (2019). Based on this we derive our baseline on-grid customer demand of 385 TWh in 2030. This demand projection corresponds to the '*Status Quo*' state (i.e. a scenario under which we assume no additional household connections to be added between now and 2030). The resulting CAGR of customer demand under the *Status Quo* state is 2.10% (3% if South Africa is excluded) over the period 2018 to 2030. Adjusting this level of demand for assumed technical losses, results in gross demand of 427 TWh in 2030 for the SAPP region, of which 305 TWh (71%) represents the gross demand of South Africa and 123 TWh (29%) the gross demand of the other 11 countries.[36]

### 3.4.2. Demand Stemming from New Household Connections

Having determined the electricity demand forecast of existing residential and non-residential customers, the last step is to add any incremental demand stemming from new household connections that are forecast to be connected to the grid in each country over the forecast horizon. In order to determine the number of households to be connected under each of the access rate scenario, we relied on data contained in the 2019 World Energy Outlook and the underlying electricity access database by the IEA, which reports data on national, urban and rural electrification rates (IEA, 2019a).

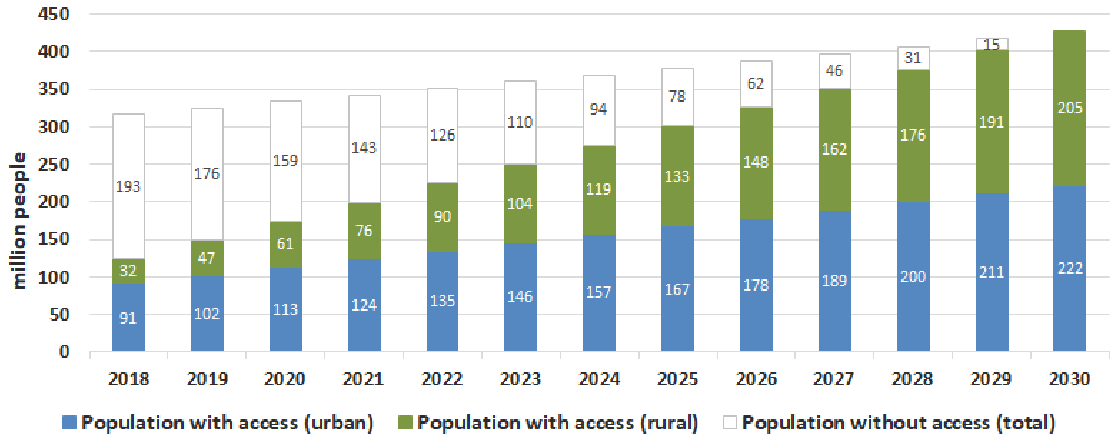
At the end of 2018, the SAPP region was home to 316 million people out of which 123 million had access to electricity (IEA, 2019a), corresponding to an access rate of

[35] This assumed annual growth rate in demand for the non-residential sector, including commercial and industrial customers is in line with Castellano et al. (2015), SAPP Pool Plan (2017) and our review of utility annual reports and historical growth rates, where both decomposition by customer type and the number of residential customers were available so that we could adjust the observed growth rate for a changing number of residential connections. We note that some utilities in their annual reports provide disaggregated data by voltage level only, and therefore the consumption of low voltage customers includes consumption by non-household customers, such as small businesses. For the split of residential and non-residential demand we had data for Botswana (residential demand representing 33% of domestic sales), Lesotho (32%), Malawi (45%), Mozambique (19%), South Africa (25%), eSwatini (36%), Tanzania (45%) and Zimbabwe (33%). For other countries we used an average of residential demand for those countries for which data were available, excluding SA given the relatively higher share of non-residential demand and the fact that SA is considerably different to other countries in the region. The residential share in Mozambique is relatively low due to Mozal, an aluminium smelter with annual consumption of around 7,656 GWh, corresponding to peak sent-out demand of 1,000 MW, annual sent-out demand of 8,059 GWh and T&D losses of 5% (SAPP Pool Plan, 2017; JICA, 2018a). Therefore, when calculating the average residential demand for countries for which data were available, we adjusted the residential share in Mozambique and excluded the consumption of Mozal, bringing the residential share up to 43% in Mozambique. We note that the split of residential and non-residential demand affects our electricity demand forecast only by the fact that we apply a different growth rate to residential and non-residential consumption, with the assumed growth rate being higher for the latter.

[36] For 2040, gross demand under the '*Status Quo*' state of the world is projected to be 532 TWh, out of which 364 TWh (68%) is the demand of South Africa and 168 TWh (32%) the demand of the other 11 countries in the region.

39%. According to the current population forecast, 427 million people will be living in the SAPP region in 2030 (WDI, 2020), implying that if the policy target for universal electricity access is to be achieved, over 300 million people would need to be connected between now and 2030 in the region (131 million in urban areas and 173 million people in rural areas). This would mean connecting on average around 25 million people per annum over the forecast period (2019-2030), as shown in **Figure 5**. Connecting 25 million people per annum in the SAPP region, is about 4.5 times higher than the rate at which people have been gaining access in the SAPP region on average in the recent past, measured over the period 2013 to 2018, as discussed above (**Table 7**).

**Figure 5: Population with access and the trajectory needed to achieve 100% access by 2030**




*Source: Authors based on IEA (2019a) and WDI (2019).*
*Note: Actual data for 2018 and authors' forecast thereafter. In the forecast, we assumed the same number of connections for each year needed to achieve the defined access target (here universal access target by 2030).*

To estimate the incremental demand for electricity under each of the '*Target Access Rate*' state of the world, we first determine the number of households that would need to be connected to achieve a given electricity access target in each country. The access target and the year by which this target is achieved has direct implications for the number of people to be connected each year and ultimately on the overall costs of increasing the rate of electricity access. While the generation optimisation model has been set up to run and assess any electricity access targets to be achieved, here we consider the following scenarios:

- '*Status Quo*' state of the world, assuming no new household connections; and
- '*Target Access Rate*' state of the world, under which we look at the following sub-scenarios:
  - *'Target Access Rate (S1)':* Scaling up electricity access based on the current rate of progress in each country:

- *'Target Access Rate (S2)':* Achieving a 70% access rate (or higher if the current rate of progress would result in higher than 70% access target in a country in the target year)[37];
- *'Target Access Rate (S3)':* Achieving universal access across each of the 12 different countries, regardless of their current starting point or the recent rate of progress.

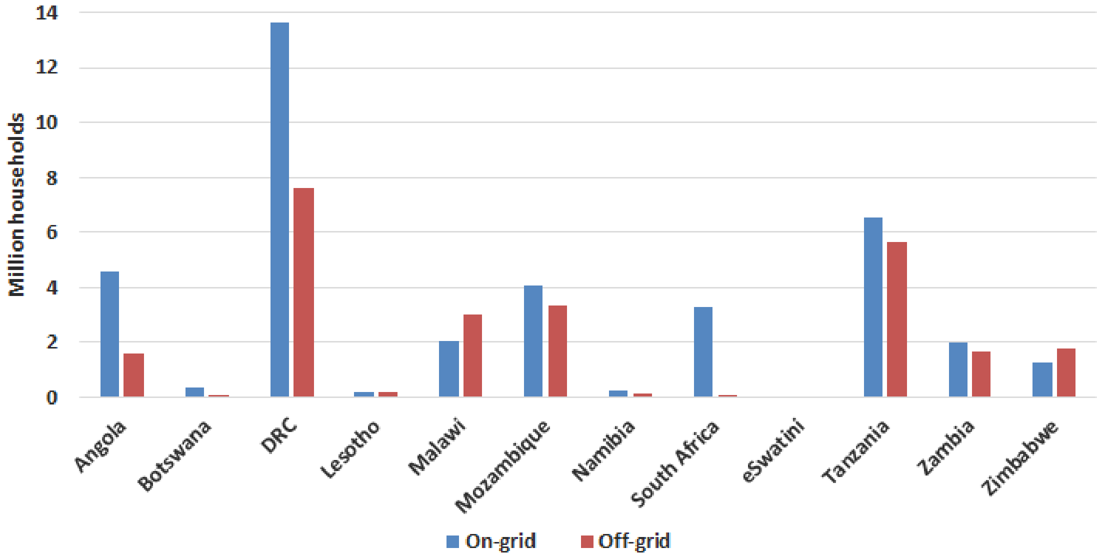
The above four scenarios are run for both the target year 2030 and 2040. *'Target access rate (S3)'* with target year 2030 is in line with the current SDG 7.1.1 universal access objective, while scenario *'Target access rate (S3)'* with the target year set to 2040 effectively means shifting the universal electricity access target by a decade.

As discussed above, in our analysis we follow OECD/IEA (2017) and assume that on-grid access constitutes the least cost option for households in urban areas and for 30% of households in rural areas. Starting from the number of people currently lacking access in urban and rural areas in each country and applying rural and urban population forecasts for each country, this means that 183 million people would need to be connected to the grid (131 million people in urban areas and 52 million people in rural areas) in SAPP by 2030 under the universal access target, with the rest (117 million people) being electrified through an off-grid solution.

Considering the average household size in each country as per national demographic surveys and the United Nations data booklet (MPSMRM et al., 2014; NSA, 2017; ZimStat, 2017; Statistics Botswana, 2018; UN, 2017b; UN, 2019), this implies 38.4 million households would need to be connected to the grid and 25.2 million households to an off-grid solution in SAPP by 2030 to meet the universal access objective in the SAPP region (**Figure 6**).

[37] Under the current rate of progress, an access rate greater than 70% is forecast to be achieved in Botswana, Lesotho, eSwatini and South Africa (refer to ***Figure 2*** above).

**Figure 6: Households connections required to achieve universal access (2030)**




*Source: Authors based on OECD/IEA (2017), IEA (2019a) and WDI (2019). Household sizes are based on national demographic surveys and the United Nations data booklet (MPSMRM, 2014; NSA, 2017; ZimStat, 2017; Statistics Botswana, 2018; UN, 2017b; UN, 2019).*
*Note: The rural access rate in South Africa was 92% at the end of 2018 (IEA, 2019a). Nevertheless, due to increased urbanisation, the absolute number of people living in rural areas is forecast to decrease as per WDI (2019). Therefore, most households in South Africa are expected to be connected to the grid.*

The number of households to be connected under a less stringent electricity access scenario is naturally lower and corresponds to 10.3 million new on-grid households connections under the current rate of progress and 25.4 million new on-grid households connections under the 70% access target to be achieved in 2030.[38] Households are assumed to be connected progressively over time, with the same number of households assumed to be connected in each year over the forecast horizon. Having determined the number of rural and urban households that gain access under each of the electricity access scenarios in each country, and the type of access solution, the final step is to estimate the electricity consumption of the newly grid connected households over the forecast horizon. Consumption of those newly connected households tends to be low and is often cited as one of the barriers to electrification (e.g. Lee et al., 2019; Blimpo and Cosgrove-Davies, 2019). In doing so we follow OECD/IEA (2017) and assume that a newly connected urban household will consume 500 kWh per year and a newly connected rural household 250 kWh per year, with their consumption increasing by 4% per annum over the forecast horizon.[39] In view of the limited number of appliances

[38] For any electricity access target below 100% we further assumed the split between the number of newly connected households in rural and urban areas. To do this we first calculated the access gap in terms of the number of rural and urban household yet to be connected. We then assumed that the gap is reduced by the same percentage for rural and urban households by 2030 to achieve the access rate target being considered. We then followed the same approach as under the universal access target and assume that 30% of households in rural areas that are connected by 2030 receive a grid connection and 70% an off-grid connection, and all households in urban areas are connected to the main grid. Finally, we assume that the same number of households are connected each year between now and 2030 to achieve the 2030 access target.

[39] It is worth noting that while we have assumed the same initial consumption per household across countries, the number of people per household tends to be lower in countries with higher GDP per capita and, hence, the resulting per capita consumption in those countries will be higher. For household sizes we relied on the national demographic surveys when available, which we complemented

households would be able to power when consuming only 250–500 kWh per annum, we also run a scenario under which the starting point of consumption is significantly higher. Under this high consumption scenario (S4), the starting point of consumption for new residential connections is 1000 kWh and 500 kWh per annum in urban and rural areas, respectively.

According to the multi-tier framework for access (Bhatia and Angelou, 2015), such a level of consumption corresponds to Tier 3 for households in urban areas, and Tier 2 and Tier 3 for households in rural areas, depending on the consumption scenario considered. Since the affordability of electricity among rural households is likely to be more constrained, the assumed initial consumption is lower than for urban households. We also note that the objective of our study is to provide an estimate of the costs of a consumption bundle that is considered sufficient to meet basic electricity needs, which takes into account trade-offs people are facing due to affordability issues between their energy needs and other demands. For example, 500 kWh per household per year would allow for electricity services sufficient to power a mobile phone, four lightbulbs operating for a few hours a day, a fan for three hours a day and a television for a few hours a day using standard appliances (IEA, 2020b). The extended consumption bundle of 1,000 kWh per annum would additionally allow for a refrigerator and increase the hours for use of the fan and television (IEA, 2020b). By way of context, a subsistence level of consumption is usually defined as 30 kWh/month per household (Kojima et al., 2016; Foster and Rana, 2020).

Under the current rate of progress (S1), which reflects the average rate at which new household customers were connected in the period from 2013 to 2018 in each country, the incremental consumption stemming from new connections (both on-grid and off-grid) is estimated to increase overall customer demand only marginally, by about 8.0 TWh by 2030. This increases to 32 TWh under the universal access scenario to be achieved by 2030 (S3), and further to 64 TWh under the universal access scenario and high consumption of those newly connected. This level of incremental consumption suggests that, regardless of the access target, the demand stemming from those newly connected households is low. This is in line with other studies that confirm that average electricity consumption of those newly connected tends to be low (e.g. Climatescope, 2018; Blimpo and Cosgrove-Davies, 2019; Lee et al., 2019). In other words, it will take time for newly

with the United Nations data booklet (MPSMRM, 2014; NSA, 2017; ZimStat, 2017; Statistics Botswana, 2018; UN, 2017b; UN, 2019).

connected households to reach the same consumption level as currently connected households, and therefore the impact of newly connected households on overall electricity demand is expected to be limited at first and will only increase over time.

The highest share of this incremental consumption is on-grid, which is driven by a higher share of on-grid connections of those newly connected and the assumed higher consumption of those living in urban areas. The incremental on-grid consumption due to new household connections is estimated at 6.4 GWh in 2030 under the current rate of progress (10.3 million households connected to the main grid) and increases to 24 GWh with universal access by 2030 (38.4 million households connected to the main grid in the forecast horizon). The incremental on-grid consumption increases further to 48 GWh in the target year under the high consumption scenario. Demand projections for the SAPP region with the target year of 2030 are presented in **Table 8**, with **Figure 7** and **Figure 8** providing country-level detail. Further country-level detailed demand data for selected scenarios is provided in **Annex 6**.

To put these figures into perspective, the current (2018) level of on-grid consumer demand in the SAPP region is around 300 TWh and is projected to be 385 TWh in 2030 under the '*Status Quo'*. This means that the amount of power that would need to be injected onto the transmission network to meet the incremental load of newly connected households would increase by a mere 1.7% under the current rate of progress and 6.2% under the universal access target by 2030. We note that even if the consumption of those newly connected was double that considered under the base case scenario, the incremental load due to new connections would increase sent-out demand in 2030 by 12.5%, which can be viewed as an upper bound on the possible range of demand growth due to new connections.

With this incremental load, on-grid electricity consumption is forecast to grow on average between 2.3 and 3.1% per annum in the forecast period (3.3 and 5.9% if SA is excluded from the SAPP average), with the higher estimate corresponding to the universal access target and high household consumption. To put these figures into perspective, the historical growth rate in electricity demand in the whole of Africa was 3% per annum between 2010 and 2018 (IEA, 2019a) and 2.8% between 2015 and 2018 among SAPP countries (SAPP, 2016; SAPP, 2017; SAPP, 2018).

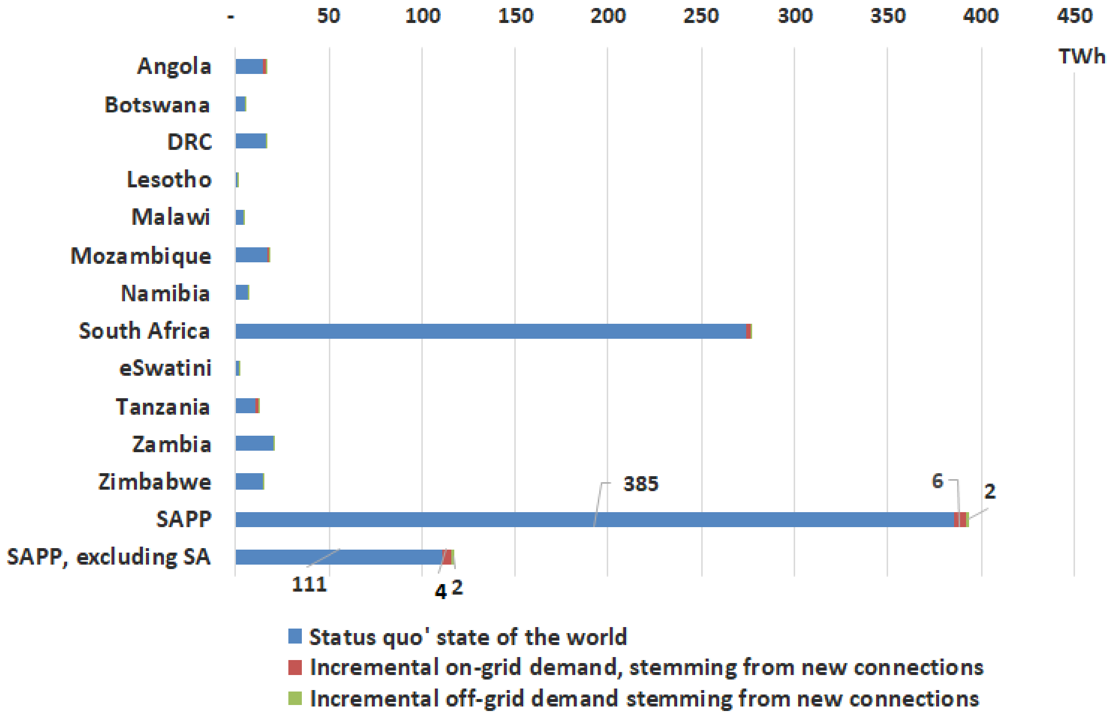
**Table 8 Scenarios considered with a target year of 2030 and resulting demand assumptions**

| Achieved electrification access rate and resulting demand scenarios | Status Quo (no incremental connections) | Current rate of progress (S1) | 70% access target or higher (S2) | Universal access (S3) | Universal access + high consumption (S4) |
|---|---|---|---|---|---|
| **Achieved electrification access rate (2030)** | 29% | 45% | 75% | 100% | 100% |
| **Achieved electrification access rate, excluding SA (2030)** | 19% | 35% | 70% | 100% | 100% |
| **Status Quo demand (2030), GWh** | 385,099 | 385,099 | 385,099 | 385,099 | 385,099 |
| **Incremental on-grid demand due to new connections (2030), GWh** | **n/a** | **6,441** | **15,877** | **24,011** | **48,022** |
| **Incremental off-grid demand due to new connections (2030), GWh** | n/a | 1,565 | 4,976 | 7,892 | 15,783 |
| **Total demand in target year compared to current / excl. SA** | 129% / 143% | 131% / 148% | 134% / 160% | 137% / 171% | 145% / 199% |
| **On-grid sent-out demand in the target year (2030), GWh** | 427,470 | 434,627 | 445,111 | 454,148 | 480,827 |
| **Increase in on-grid sent-out demand due to new connections (2030), GWh** | **n/a** | **7,157 (1.7%)** | **17,641 (4.1%)** | **26,678 (6.2%)** | **53,357 (12.5%)** |

*Source: Authors based on IEA (2019a), IEA (2019b), IEA (2018), IEA (2017), IEA (2015), the WDI (2019), SAPP Pool Plan (2017), JICA (2018a), JICA (2018b), Norconsult et al. (2017), Rocky Mountain Institute (2019), SA IRP (2019) and utility annual reports.*

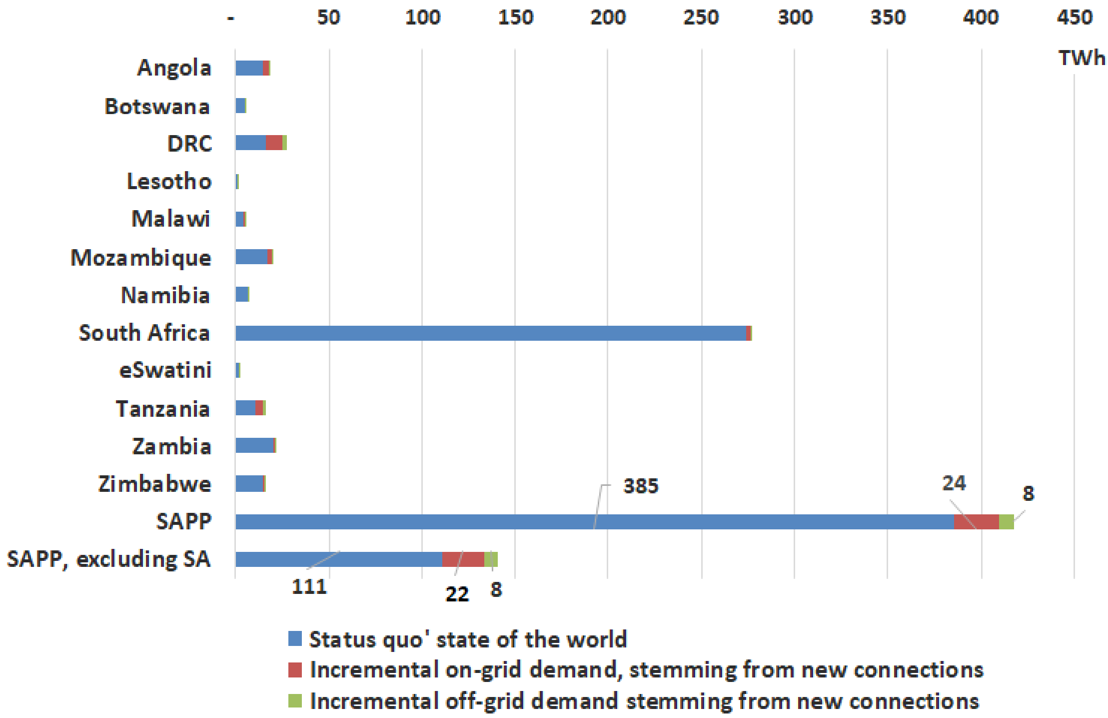
*Note: The performance of countries with respect to providing access to electricity has varied a lot in the recent past. When deriving the current rate of progress, we do this for each country individually by looking at the average annual change in the number of people with access from 2013 to 2018 (recent rate of progress across countries is summarised in **Annex 1**. In order to derive sent-out demand, consumption is adjusted upwards for the level of technical losses to derive the amount of electricity to be met by generation and imports at the point of injection onto the transmission network. In deriving the amount of sent-out electricity, we keep the level of technical losses defined as a % of sent-out constant throughout the forecast horizon for all countries with the exception of Mozambique. In Mozambique technical losses increase slightly over the forecast horizon as consumption of Mozal is assumed to stay constant over the forecast horizon in line with SAPP Pool Plan (2017), and therefore the share of Mozal in overall consumption decreases over time. We note that total electricity consumption in 2030 excludes consumption of existing off-grid customers (residential and non-residential). Country level on-grid consumption data feeding into the least-cost optimisation model are provided in **Annex 6**, including the development of consumption and sent-out demand on the grid, and the development of incremental off-grid electricity consumption over the whole forecast period starting from its current level (i.e. 2018 to 2030).*

**Figure 7: Projection of customer demand under the current rate of progress – S1 (2030)**




*Source: Ibid.*

**Figure 8: Projection of customer demand under the universal access target – S3 (2030)**




*Source: Ibid.*

# 3.5. Methodology

To calculate the generation cost of providing access to the grid, we construct an optimisation model that minimises the generation investment and operating cost, subject to meeting demand for each exogenously defined electricity access target. The model meets current and incremental electricity demand over the period 2018 to 2030 or 2018 to 2040 (depending on the target year for access) while minimising the present value of the overall generation cost. That is, the model finds a solution that minimises the overall costs of investments and operation over the planning horizon for each exogenously defined demand scenario, as shown in (1).

$$MinC(demand\ scenario) = \sum_{t=1}^{T} \frac{\left(\sum_{i=1}^{I} G_{it} FC_{it} + \sum_{i=1}^{I} QP_{it}\, VC_{it}\right)}{(1+r)^t} \qquad (1)$$

where:[40,41]

- *G* is the installed capacity (MW) of power plant *i* in period *t*;
- *FC* is the annuitized fixed costs per MW of power plant *i* in period *t*, which for an existing power plant represents only the annual fixed O&M costs whereas for a newly constructed power plant represents the annual fixed O&M cost and the annuitized capital cost;
- *QP* is the electricity production (MWh) from power plant *i* in period *t*;
- *VC* is the variable costs per MWh of power plant *i* in period *t*;
- *r* is the real discount rate used to express all costs as the present value at a common point in time.

The solution to the optimisation problem determines the optimal choice of generation capacity, generation output by each power plant and cross border interconnector flows for the countries in the SAPP region for each exogenously defined demand scenario. In order to understand the incremental costs of providing access, we compare the respective costs for two states of the world:

[40] For simplicity, here we show time using a single subscript, *t*. Generation variable operating costs (fuel costs and variable operations and maintenance costs) are applied to generation output on an hourly basis whereas the annuitized fixed costs of generation investment and the annual fixed cost of generation operations and maintenance are applied to installed capacity on an annual basis.

[41] Investment costs are represented as an annuity, using the technical life of the power plant. The annuity cannot be avoided by subsequently closing a newly constructed power plant.

- '*Status Quo'*. This state of the world considers the cost of generation to provide electricity to non-residential customers (commercial, industrial, agricultural and public sector) and only currently connected households, and the quantity demanded equals the existing load and its development over time; and
- '*Target Access Rate*'. This state of the world considers the cost of generation to provide electricity not only to the non-residential customers and currently connected households, but also to the incremental population that need to be connected to reach the defined target access rate, and where the quantity demanded equals the load of customers under '*Status Quo*' plus the incremental load of households newly connected to the grid in order to meet the defined electricity access target.

The difference in the present value cost between these two states of the world is the incremental cost of expanding and serving the incremental load of households that are newly connected to achieve each defined electricity access target. By using the same non-residential demand and existing household demand across all scenarios, we isolate the cost of solely connecting new household customers. Such an estimation requires an extensive set of power system data for each country. Key inputs into the optimisation model include: existing and committed power plants and their capacity, candidate power plants and their capacity, power plant capital costs (for committed and candidate plants), operating and maintenance costs, power plant fuel conversion efficiency, fuel costs, fuel availability in each country, plant lifetimes, power plant availability, availability profiles for renewable generation, transmission interconnector capacity between countries and interconnector losses, and demand for electricity for each country (in terms of annual energy, annual peak demand and hourly demand as a proportion of peak demand). Further details of the power sector expansion model and its application here, as well as the detailed power system data underlying our analysis are set out in **Annex 3** and **Annex 4**.

Having evaluated the incremental system generation costs, we then derive the incremental levelized cost of electricity (LCOE) supply related to generation per unit of incremental electricity consumption of the newly grid connected households. The incremental LCOE is calculated as the present value of the total incremental cost related to building and operating the power generation assets needed to serve the incremental load, divided by the present value of total incremental consumption over the period under consideration:

$$LCOE_{\ US\$/MWh} = \frac{\sum_{t=1}^{T} \frac{(\sum_{i=1}^{I} G_{it}FC_{it} + \sum_{i=1}^{I} QP_{it}VC_{it})}{(1+r)^t} - \sum_{t=1}^{T} \frac{(\sum_{i=1}^{I} G_{it}FC_{it} + \sum_{i=1}^{I} QP_{it}VC_{it})}{(1+r)^t}}{\sum_{t=1}^{T} \frac{(IE_t)}{(1+r)^t}} \quad (2)$$

where:

- *G*, *FC*, *QP*, *VC* are defined in the same way as in (1) and where the first ∑ refers to the present value cost under '*Target Access Rate*' and the second ∑ refers to the present value cost under '*Status Quo*', i.e. we use the incremental cost, which equals the difference in present value cost between the two scenarios;
- *IE* is the incremental electricity consumption related to serving the incremental load stemming from new connections in period *t*, i.e. the difference in load between the '*Target Access Rate*' and '*Status Quo*'; and
- *r* is the real discount rate (in our case 6%).

Finally, we also express the cost per incremental household grid connection. Given that households are connected over time (rather than in one single year), taking a present value incremental generation cost up to 2030 or 2040 and dividing that by the present value number of incremental household connections would make it difficult to understand what this cost means for connecting and serving any one household. Therefore, we rely on the estimated incremental levelised cost from (2) and multiply it by a given consumption bundle of a representative household over a period of time.

## 3.6. Results on Investment Needs and Costs of Supply

We estimated the present value total forward looking on-grid generation cost[42] in the SAPP region from 2018 to 2030 for each exogenously defined electricity access rate scenario in line with equation (1). Under the '*Status Quo*' (i.e. assuming no incremental household connections between now and 2030), the present value forward-looking

[42] A forward-looking cost is a cost that may vary in future, which excludes investment costs of existing power stations, which are sunk. All costs reported in the results section of this chapter are in US$2018, with the present value date of 1 January 2018, unless otherwise stated.

generation cost is estimated at US$ 146 billion for the period 2018 to 2030. Compared to this, the additional fixed and variable generation cost of meeting the universal access target by 2030 is low at about US$ 5.2 billion in the SAPP region (S3), reflecting the relatively low incremental demand of the newly connected households. The present value cost of providing universal access increases to US$ 11.4 billion, assuming a higher initial consumption for newly connected households (S4).

As expected, most costs relate to fuel costs and other operating costs, with investment costs being a relatively small proportion of overall generation costs. This is partly driven by the fact that we do not include sunk costs or the entire investment cost of newly built power plants with plant lives beyond the planning horizon. Instead, we express the investment cost of newly constructed plants as an annuity and consider the cost of the annuity only until 2030 (or 2040 with the later access target). We do this to ensure that the model takes unbiased decisions regarding capital costs and operating costs, as well as to understand the cost of supply from now until the defined access target year. However, incremental investment costs comprise about half of total incremental costs in meeting the universal access target in 2030 (**Table 9**).

**Table 9 Forward looking generation costs under different access scenarios (2018-2030)**

| Type of cost (US$2018 million) | Status Quo | Current rate of progress (S1) | 70% access target or higher (S2) | Universal access (S3) | Universal access + high consumption (S4) |
|---|---|---|---|---|---|
| **Generation investment cost** | 9,370 | 9,869 | 10,830 | 11,487 | 14,522 |
| **Interconnector investment cost** | 264 | 264 | 264 | 264 | 264 |
| **Fuel cost** | 72,821 | 73,415 | 74,150 | 74,904 | 76,641 |
| **Variable operating costs** | 18,573 | 18,650 | 18,764 | 18,875 | 19,164 |
| **Fixed operating costs** | 45,304 | 45,515 | 45,802 | 46,046 | 47,095 |
| **Total cost** | **146,332** | **147,714** | **149,810** | **151,577** | **157,687** |
| **Incremental total cost compared to Status Quo** | **n/a** | **1,382** | **3,478** | **5,245** | **11,355** |
| **Increase in total cost compared to *Status Quo*** | **n/a** | **0.9%** | **2.4%** | **3.6%** | **7.8%** |

*Source: Authors.*

To help put the cost of providing universal access into perspective, the incremental present value generation cost of serving the demand growth of existing customers from 2018 to 2030 with no new household connections (*Status Quo*), is US$ 19.4 billion. This is almost four times greater than the present value generation cost from 2018 to 2030 of meeting the additional demand of newly connected households to the main grid under the universal access target by 2030 (S3). As an alternative way to put the cost of providing universal access into perspective, if water availability from all hydro plants in the SAPP region was 10% less than expected over the period 2018 to 2030, representing the effects of droughts or climate change, present value costs under the *Status Quo* scenario would increase by US$ 2.9 billion or by a little over half of the cost of providing universal access.

Following equation (2), on average for the SAPP region, the levelised cost related to generation of meeting incremental household demand stemming from new connections is estimated at between 63 and 70 US $2018 per MWh for the period from 2019 to 2030, depending upon the access rate scenario. Generally, for a relatively low increase in new connections, cheaper generation sources can be used, while for a higher increase more expensive generation options are used as the cheaper options become exhausted or as interconnection between countries becomes congested, increasing the levelised cost per MWh (**Table 10**).[43]

**Table 10 Levelised generation cost due to incremental household connections (2019-2030)**

| US$2018/MWh | Status quo | Current rate of progress (S1) | 70% access target or higher (S2) | Universal access (S3) | Universal access + high consumption (S4) |
|---|---|---|---|---|---|
| **Levelised cost** | n/a | 63.36 | 64.69 | 64.51 | 69.83 |

*Source: Authors.*
*Note: The cost is expressed at the consumer point of off-take from the grid, which is above the cost at the point of supply to the transmission grid due to technical losses incurred in the transmission and distribution network.*

As a sensitivity of the universal access scenario (S3) we explore the cost of grid generation if only 80% of all new household connections in urban areas and 20% of household connections in rural areas are grid connected. Fewer grid connected customers reduces the demand served by the grid, reducing the additional forward looking fixed and variable grid generation cost of meeting the universal access target by 2030 by US$ 1.3 billion to US$ 4.0 billion, and reducing the levelised cost related to generation of meeting incremental household demand stemming from new connections by 0.25 US$2018 to 64.25 US$2018.

We also estimate the incremental generation cost of connecting and serving a single household, using the above levelised generation cost for the 2030 target year. Depending on the consumption bundle, the generation related costs of serving one household for a year are estimated at between 16 and 65 US$ initially, with the lower estimate

[43] We note that LCOE is an indicator of the average cost of electricity from a power station, but it does not necessarily reflect the value of the power station to the system (a measure of the levelised avoided cost of energy and capacity is required to reflect the value to the system). In particular, solar PV without storage tends to produce its maximum output around noon whereas the daily demand peak in Africa generally occurs in the evening. Back-up generation capacity to solar PV would therefore be needed to serve the evening peak. This is reflected in the model through the hourly PV generation profile and the hourly demand profile, and also through the relatively low contribution of PV without storage to meeting capacity requirements.

corresponding to a consumption bundle of 250 kWh per annum and the higher estimate corresponding to a consumption bundle of 1000 kWh per annum. This would increase to between 25 and 99 US$ in the target year (2030) for a consumption bundle of 385 and 1539 kWh per annum, respectively, assuming a 4% compound annual growth rate in consumption of the newly connected households. The overall incremental generation cost of connecting and serving a household from 2019 to 2030 (i.e. for 12 years) is estimated at between 242 and 969 US$, again depending on the consumption bundle of any single household (**Table 11**).

**Table 11 Levelised generation cost per new household connection to 2030**

| Customer | Initial consumption in 2019 (kWh/annum) | Annual cost in 2019 (US$2018) | Annual cost in 2030 (US$2018) | Total cost - 12 years (US$2018) | Average annual cost (US$2018) |
|---|---|---|---|---|---|
| **Rural** | 250 | 16.13 | 24.83 | 242.31 | 20.19 |
| **Urban / Rural** | 500 | 32.25 | 49.65 | 484.63 | 40.39 |
| **Urban** | 1,000 | 64.51 | 99.30 | 969.25 | 80.77 |

*Source: Authors.*
*Note: The cost is expressed at the consumer point of off-take from the grid.*

We also analysed the levelised cost of consumption and the cost per new household connection with the universal access target delayed by ten years to 2040. We find that the unit levelised cost up to 2040 is between 2% and 6% lower than the generation levelised cost to 2030. The main drivers of the lower cost are the availability of natural gas in South Africa from 2030, expected additional decline in the cost of solar photovoltaics and interconnection with Angola, Tanzania and Malawi that becomes available shortly prior to 2030. Using this levelised cost to 2040, the incremental generation cost of connecting and serving a household from 2019 to 2040 (i.e. for 22 years) is estimated at between 520 and 2080 US$2018, depending on the level of consumption over that period.

Finally, we compare our results to other studies in the literature. Castellano et al. (2015) estimate the levelised cost of electricity generated in Southern Africa to be US$ 68 per MWh over the period 2010 to 2040, assuming between 70% and 80% of the population is grid connected by 2040. Spalding-Fecher et al. (2017) estimate the forward-looking cost of generation in the SAPP region to 2070 to be in the range of 50-70 US$2010 per MWh depending on the year and electricity access scenario. Adjusting for inflation from 2010 to 2018 brings the cost reported by Castellano et al. (2015) to about 68 US$2018 and the cost reported by Spalding-Fecher et al. (2017) to between 59 and 82 US$2018. Neither study is directly comparable to our estimated cost of generation, because we express our costs at the consumer off-take point (i.e. the electricity volume the customer draws from the system). Adjusting our levelised costs downwards to net out technical network losses brings them to US$ 55–57 per MWh (depending on the access scenario in 2040) for electricity delivered to the transmission network. The higher costs of both Castellano et al. (2015) and Spalding-Fecher et al. (2017) can be explained by them relying on much higher fuel prices, indicative of the general climate for forecast fuel prices at the time of their analysis.

SAPP Pool Plan (2017) reports the present value forward looking cost of generation and transmission investment to 2040 as US$ 241 billion in their full integration case, excluding loss of load costs. Their demand is based on adjusted utility forecasts and therefore does not map onto any one of our access scenarios. Our findings are similar where we find the present value forward looking cost of generation to 2040 to range from US$ 227 billion to US$ 249 billion depending upon the access scenario and level of household consumption (also excluding loss of load costs and capacity shortfall penalty costs).

The focus of our analysis was to estimate the incremental forward looking on-grid generation cost of achieving a given electricity access target. In other words, we do not optimise the grid extension and densification costs. To understand the overall cost of supply to unelectrified households, one would also need to consider the incremental investment and operating costs of the transmission and distribution grids, as well as last mile connection. Here we follow Castellano et al. (2015) and EIA's reference case in 2018 (EIA, 2019a) and assume that generation costs represent about 60% of electricity system costs. This would imply the total incremental cost of supply to meet incremental demand under the universal access scenario to be between 108 and 116 US$2018 per MWh of electricity consumed. Following this off-model adjustment we derive grid costs of between 4.2 USc2018/kWh under the current rate of progress and 4.7 USc2018/kWh under the universal access target and high consumption scenario.

However we note that the cost to connect and supply a household, including the costs of transmission and distribution, varies with distance to the main grid and some households will have higher or lower costs than our off-model adjustment.[44] In our analysis, we considered that approximately 60% of those newly connected would gain

[44] According to Climatescope (2018), expanding the main grid to connect new customers costs between $266 and $2,100 per household connection. Detailed geospatial data is needed to understand the costs of expanding the current grid network in each country or region, taking account of the specific circumstances of each. The results of our study of wholesale generation costs could be then used as an input into least-cost electrification planning models that have detailed geospatial data to decide on the least-cost electrification option.

access through the grid, implying that the households furthest from the grid and that are more expensive to serve would rely on off-grid solutions.

While the derived grid costs have only limited reporting value, our results are comparable to Bazilian et al. (2012) who estimate the levelised cost over the period 2010 to 2030 of generation, transmission and distribution in the SAPP region (excluding South Africa) required to achieve universal access in 2030 as 82 US$2010 per MWh (about 96 US$2018), and estimate the cost in South Africa as 89 US$2010 per MWh (about 104 US$2018). These costs are between 3% and 17% below our levelised cost estimates to 2030.

# 3.7. Conclusions

Our analysis shows that the current level of effort, as measured by the rate at which access is being extended in SSA, is insufficient to bridge the current access gap and achieve universal access by 2030. In fact, if the current rate of progress continues, less than 60% of the population in SSA would have access to electricity by the SDGs target year (2030). The situation is even more concerning among countries in SAPP, where only 45% of the population would have access to electricity by 2030 under the current rate of progress and even less if SA is excluded. This is despite a common understanding that access to affordable and modern energy is central to economic growth and poverty alleviation (OECD/IEA, 2017).

The objective of this research was to inform decision-makers and other stakeholders as to the true costs of providing access to electricity in SSA. To do so, we developed a detailed least cost optimisation model to assess the incremental generation costs of providing on-grid access to electricity to currently unelectrified households. Several studies have assessed the costs of expanding the power sector in SSA. Those studies, however, look at the overall costs of serving not only the incremental newly connected households, but also the costs of supply to existing customers whose demand grows over time. Therefore, the derived costs tend to overstate the true cost of access because they do not isolate the incremental costs of only new household connections. As a result, policymakers, might underinvest in access compared to the efficient level of investment.

Our analysis, focussed on the SAPP region, shows that achieving universal access by 2030, compared to not connecting any further households, would lead to an additional forward-looking generation cost of between 5.2 and 11.4 US$2018 billion by 2030, depending on the consumption level of newly connected households. This is relatively low compared to the overall forward-looking system generation cost of serving the current households and the non-residential sectors of the economy, estimated at 146 US$2018 billion in the SAPP region between 2018 and 2030. The incremental costs correspond to a levelized generation cost of between 65 and 70 US$2018 per MWh consumed by the newly connected households under universal access. This corresponds to between 108 and 116 US$2018 per MWh for the overall costs of electricity supply at the point of consumption, assuming that generation costs represent about 60% of the overall cost of supply. Therefore, while the level of effort required to connect new households is considerable, the incremental costs of making that additional effort is relatively low, suggesting that policymakers should strive to increase access to electricity. In fact, the levelized cost of providing access is lower than what a typical household pays for very poor alternatives to electricity, such as kerosene for lighting.

This suggests an urgent need for policymakers of countries not on target to achieve universal access by the SDG 7 target year to accelerate the rate at which electricity access is provided, and which needs to be taken into account in national and regional electricity planning. Only a handful of countries in SSA have adopted a national electrification strategy, despite the fact that having such a strategy has been seen as critical to expanding electricity access in other regions, most notably South-East Asia (Blimpo and Cosgrove-Davies, 2019). Therefore, there is a need to put in place policies, regulations and an overarching framework to drive increased investment in the power sector of most countries in SSA. The need for strong governance and institutional capacity is vital to manage that investment and channel it to economically efficient projects in view of the need to increase the current level of effort in providing access several fold to achieve the universal access target by 2030. Furthermore, we note that bridging the electricity access gap in SSA is not only about extending the limited reach of electrical connections, but also about providing reliable and affordable electricity supply, attributes that are essential to meeting other SDGs.

Our analysis also confirms the significant economic benefits of trade. Electricity trade has the effect of decreasing the overall system costs, and hence can play a vital role in overcoming the challenges of low electricity access. This is apparent from the fact that both the existing and the expected newly commissioned interconnectors interconnecting Malawi, Angola and Tanzania to the rest of SAPP countries get utilised in the least cost optimisation model. In addition, for a country naturally endowed with energy resources, receipts from exports could potentially contribute towards financing investments needed for domestic access, lowering the affordability constraint related to electricity access. This suggests, a clear policy implication of the need to consider possibilities for trade when developing national electrification strategies, which we explore further in the next chapter. This is an important conclusion, because countries in SSA are endowed with very different energy resources that could be used for power generation and yet countries have developed their power sectors largely in isolation. This has had the effect of unnecessarily burdening the power sector with additional costs, which could have been avoided.

The least-cost optimisation model developed as part of this study and the resulting levelized on-grid generation costs could be used as an input into least-cost electrification planning models. In other words, the results on levelized on-grid costs could be used to develop a supply curve for on-grid generation costs with the levelized costs varying by the electricity access target to be achieved, demand assumptions, share of renewable generation technologies or the level of interconnection between countries. Several least-cost electrification planning models have been developed for SSA (e.g. Dagnachew et al., 2017) but these take a static value of on-grid levelised costs based on standard but not optimized costs when deciding between on-grid and off-grid solutions. Therefore, using the results of our study could be a natural extension of existing least-cost electrification models.

Another potential extension of our research is to use the optimisation model developed as part of this study to look at the costs of access by country. While the results on the incremental levelised costs of providing access in the region cannot be simply taken and multiplied by the level of consumption of the newly connected customers each year for a given country, different scenarios for the "negotiated" value of imports/exports could be envisaged to understand the overall costs of providing access in each country. We note that the "negotiated" hourly value of imports/exports could be anywhere between the hourly system margin cost in the exporting country and the hourly system marginal cost in the importing country.

Finally, although our focus is on a group of countries in SSA, we note that the framework for analysis and the conclusions reached are likely to be applicable to other countries within SSA and to regions elsewhere with poor access to electricity.

## Acknowledgements

We thank Claire Nicolas, Lukas Recka, Jozef Barunik and Tomas Havranek for their helpful comments.

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# Chapter 4

# Potential gains from regional integration to reduce costs of electricity supply and access in Southern Africa

**The results of this chapter were submitted for publication to Energy for Sustainable Development** in April 2020 and resubmitted following a recommendation for minor revisions by the editor in December 2020 as: Valickova, P., Elms, N., 2020. Potential gains from regional integration to reduce costs of electricity supply and access in Southern Africa.

**Abstract:** Sub-Saharan Africa has a long way to go to ensure reliable and affordable power for all. Sub-Saharan Africa is also a region confronted with very high supply costs, significantly contributing to the lack of access. Increased power trade has the potential to reduce the cost of supply and hence play a vital role in overcoming the challenges of increasing electricity access. In this paper we analyse the benefits of trade among countries in the Southern African Power Pool, focussing on how international trade can reduce the underlying costs of supply and therefore the costs of providing electricity. Our analysis, based on a least-cost power sector expansion model, shows that the existing interconnection capacity is not utilized efficiently, meaning that countries are forgoing some benefits of power trade in the short term and also benefits of taking a regional approach to power system planning. This in turn increases the costs of supplying existing and new customers. Utilizing the existing interconnectors efficiently and building and using new interconnectors when economically beneficial to do so reduces forward-looking cost of generation by almost 6% compared to no trade. The saving is largely a result of less generation capacity being needed with full trade. Trade can also significantly contribute towards meeting other objectives, such as reducing greenhouse gas emissions. Specifically, with trade less coal fired generation is required, particularly in South Africa and Zimbabwe, and more hydro capacity is developed elsewhere in the region, particularly in the Democratic Republic of Congo and Mozambique.

**Keywords**: Sub-Saharan Africa, benefits of trade, electricity access, power sector modelling, development

**JEL classification**: Q47 (Energy Forecasting), Q41 (Demand and Supply), O20 (Development Planning and Policy), L94 (Electric Utilities), O55 (Africa)

**Funding**: This work was supported by the Charles University Grant Agency (grant number 829 317) and H2020 Marie Sklodowska-Curie Actions (grant number 681 228).

# 4.1. Introduction

As discussed in Chapter 3, despite the international commitment for universal access to modern energy services enshrined in SDG 7, SSA has a long way to go to extend electricity access to all. The lack of access to modern electricity services in SSA is often linked to affordability issues (Eberhard, 2011; Onyeji et al., 2012; Bos et al., 2018), which arise in both the supply and demand for electricity access. Supply side issues relate to limited financial resources available to undertake substantial investments in new generation and expansion of the existing grid, and/or to provide off-grid (mini-grid and standalone) solutions to reach currently unelectrified customers. Demand side issues relate to the limited ability of end-customers to pay for the initial connection (Lee et al., 2016; Lee et al., 2019) and for their recurring electricity consumption, which for many households represents a substantial share of their income (Kojima et al., 2016; Blimpo and Cosgrove-Davies, 2019, Sievert and Steinbuks, 2020).

To close the current access gap, it is therefore imperative to reduce the underlying cost of supply. Our hypothesis is that increased cross border trade in electricity could play a vital role in driving down supply costs, thus helping to overcome one of the key causes of low electricity access. Several studies have focussed on the benefits of regional integration on reducing the costs of supply and improving security of supply (e.g. Bowen et al., 1999; Graeber et al., 2005; Gnansounou et al., 2007; Timilsina and Toman, 2016). However, to the best of our knowledge there is no recent study in the context of SSA that assesses the potential for regional integration not only to reduce the costs of supply but also to contribute to meeting the objective of universal access to electricity.

The closest to our work is a study by Rosnes and Vennemo (2008, 2009 and 2012), who estimated the required investments to meet the growing demand for electricity in SSA over a 10-year period under different access targets and different levels of regional integration. The access scenarios considered by the authors are a constant access scenario in which access rates are kept at their 2005 levels and a scenario in which stated national access targets are met, both significantly below what is needed to extend electricity to the whole population in SSA. The authors also did not attempt to estimate the incremental unit costs of serving the newly connected households (i.e. look at the change in costs with and without incremental access divided by the incremental demand). Finally, the last year of their forecast was 2015, the target year for the Millennium Development Goals, which means that much has changed since undertaking their study. In particular, new energy sources have become available in the region (gas in Mozambique and in South Africa) and the costs of renewable generation such as solar PV, which is widely available in region, have plummeted. These new energy sources have the potential to change the benefits of regional integration. Our study therefore takes a fresh look at the benefits of trade, in the context of meeting the universal access target by 2030, as set out in SDG 7.

While this study is primarily concerned with how increased power trade could reduce the cost of supply, lowering the affordability barrier to electrification, it is worth noting that countries in SSA face a multitude of power sector challenges that play an important role in explaining why closing the electricity access gap has proved to be so difficult. Other challenges include old and insufficient generation capacity and ageing transmission and distribution assets, affecting the reliability of power supplied through the grid and uptake even once the grid has been expanded to the area, and a lack of national electrification plans and an adequate institutional and regulatory framework that would help to attract the private sector financing needed to bridge the funding shortfall (Blimpo and Cosgrove Davies, 2019). Indeed, a lack of financing options to make connection charges affordable is cited as a reason for the high up-front charges for a grid connection that in turn create a barrier to access (Golumbeanu and Barnes, 2013).

In addition, even those with access to electricity in SSA are often faced with unreliable supply as a result of country power sectors operating with a constant energy shortage (Medinilla et al., 2019). Unreliable supply and frequent blackouts limit the possibilities to use electricity in productive uses, and further increase the underlying cost of supply by requiring customers who need a reliable supply to invest into expensive and fuel intensive back-up generation (IFC, 2019; Blimpo and Cosgrove-Davies, 2019; Medinilla et al., 2019), having a negative impact on economic welfare. The economic losses associated with power supply interruptions, both planned and unexpected, are high and have been extensively studied (World Bank, 2009; Briceno-Garmendia and Foster, 2009; Oseni, 2013; Abotsi, 2016; Agwu et al., 2019). For example, Oseni (2013) estimated that the costs of both planned and unexpected outages can result in up to a 5 percent reduction in GDP.

Unreliable supply is often coupled with high electricity tariffs (Kojima and Trimble, 2016; Trimble et al., 2016). Furthermore, even in situations where electricity prices are low, this tends to be a result of heavy subsidies (World Bank, 2009; Huenteler et al., 2020). Still, these tariffs and subsidies provided by the governments are often insufficient to cover the overall costs of supply (IMF, 2013; Trimble et al., 2016; Huenteler et al., 2020), undermining the financial viability of utilities in SSA (Kojima et al., 2016) and reducing the ability of the sector to undertake the investments needed to provide access. Several studies have shown that cross border trade can also help to tackle issues other than the cost of supply faced by the power sector in SSA, such as unreliable electricity supply (ECA, 2009; Oseni and Pollitt, 2016).

Despite these obvious benefits of electricity trade, countries in SSA have developed their power sectors largely in isolation, predominantly relying on electricity generated within their own borders.[45] A push to increase regional cooperation began in SSA with the creation of four regional power pools: Southern African Power Pool (SAPP), Central African Power Pool (CAPP), West African Power Pool (WAPP), and Eastern Africa Power Pool (EAPP). The power pools are aimed at coordinating the supply and demand for electricity so as to minimise the cost of meeting demand and to minimise the need for and cost associated with load shedding (SAPP, 2018). However, to date the implementation and effectiveness of these power pools in SSA remains limited, largely due to a political preference for bilateral agreements, lack of trust among countries and a clear preference for ensuring security of supply within the national borders over relying on the regional market (Medinilla et al., 2019). Even in SAPP, which is the most advanced power pool in SSA, the amount of power exchanged in the region remains limited, representing under 2% of the system load of SAPP countries (SAPP, 2019; Medinilla et al., 2019).

In this study we build on the power system planning model discussed in Chapter 3, and add endogenous decisions regarding interconnector investments. Hence, we quantify the benefits of regionally optimised cross-border electricity trade among countries grouped under the SAPP over the period 2019 to 2030, which coincides with the policy target for achieving universal access to electricity. That is, we look at how increased power trade could reduce wholesale costs of supply, and thus contribute towards lowering the affordability barrier to electrification in the region. In doing so, we look at the least cost electricity supply options under different levels of regional integration and scenarios for electricity access targets.

[45] Although relatively limited compared to their supply needs, countries in Africa have used bilateral contracts for cross border supply of electricity for many years. For example, electricity generated by the Hidroeléctrica de Cahora Bassa (HCB) power station in Mozambique has been exported to South Africa since 1977, although those exports were interrupted during the civil war in Mozambique (HCB, 2018; ECA, 2009). Medinilla et al. (2019) note other examples of cross border trade such as DRC-Zambia in the 1950s, Zambia Zimbabwe in the 1960s, Nigeria-Niger, Ghana-Togo/Benin in the 1970s and the regional hydropower projects in the Senegal river basin, which began producing electricity in 2001. However, Medinilla et al. (2019) also discuss the inflexibility of bilateral arrangements to address demand peaks and overcome challenges such as power line outages.

In the remainder of this chapter we first provide an overview of the benefits of trade and the power systems in the SAPP region. We then describe the methodology used to estimate the benefits from trade and the level of demand feeding into the least-cost optimisation model. Thirdly, we provide results on the potential for power trade among countries in the SAPP region not only to bring economic benefits, and hence lower the affordability barrier to electrification, but also to provide environmental benefits. Finally, we draw conclusions and discuss possibilities for future research in this area. A number of annexes is provided detailing the supply and demand data feeding into the optimisation model, as well as selected results.

## 4.2. Benefits of trade and the power systems within SAPP

*Benefits of trade*

Trade in electricity has the potential to improve affordability by reducing costs (USAID, 2018a). It does this through increased competition allowing lower cost regional supplies to displace higher cost local generation, through better optimisation of generation resources, through economies of scale in generation with trade allowing for larger power stations to be developed, and by sharing of reserves (ECA, 2010; Timilsina and Toman, 2016; IEA, 2019b). At the same time, trade can improve reliability of supply through increasing diversity of supply and by providing a possible alternative source of supply when there is a localised supply interruption (Gnansounou et al., 2007; Wittenstein et al., 2016; USAID, 2018a).

Trade can also help to facilitate the integration of intermittent renewable generation sources through shared reserves, thus allowing more non-conventional renewable generation capacity to be developed and diversify the generation mix (ESMAP, 2010; Montmasson-Clair and Deonarain, 2017). This is important due to recent and projected cost reductions for certain intermittent renewable generation sources and the significant potential for intermittent renewable generation in the region. Hermann et al. (2014) find that Southern Africa has the potential for 163,000 TWh of generation from solar PV and 10,000 TWh of generation from wind.[46]

[46] Hermann et al (2014) define Southern Africa as excluding DRC and Tanzania and therefore the potential for generation from solar PV and wind in the SAPP region will be greater.

Included within the above list of benefits is the ability for regional trade to help countries better cope with droughts. This is especially relevant to the Southern African region, which consists of several hydro-rich countries in the centre and North (Angola, DRC, Zambia, Zimbabwe and Mozambique) and thermal-rich countries in the centre and South (South Africa, Botswana and Zimbabwe in coal and Mozambique in natural gas and coal). Thermal generation can be used to supplement hydro generation during periods of drought and surplus hydro generation can be used to displace the use of more expensive fossil fuels during periods of high water inflows. Indeed, it was the drought that hit Southern Africa in 1992 that contributed to the creation of the SAPP in 1995 (Medinilla el al., 2019).

Leveraging the SAPP region's diverse energy resource potential through trade, could make the system more efficient and reliable as a whole. For example, Mozambique has a large hydro potential, coal and natural gas reserves and a significant solar and wind potential (Hussain, 2015). The Democratic Republic of Congo (DRC) has the potential to install up to 100,000 MW of hydro generation capacity (USAID, 2018a). Zimbabwe's endowments include coal, coal-bed methane and hydro (ADB, 2020). Angola and Zambia have significant hydro resources, while Malawi has significant hydro and coal resources. South Africa has abundant coal reserves and recently discovered natural gas off its Southern coast (USAID, 2018b).

Development of the hydro power station Hidroeléctrica de Cahora Bassa (HCB) in Mozambique is an example both of trade being used to unlock low cost energy sources and of trade helping to achieve economies of scale. Trade allowed the low-cost hydro generation from HCB to be exported to South Africa, which was the only market large enough for the power station (ECA, 2009). An example of trade helping to optimise generation resources is the export of hydro based generation during the rainy season and the import of power during the dry season, and the export of hydro generation during a wet year and the import power during a drought year. Another way in which trade can be used to optimise generation is between countries that have differences in the pattern and timing of demand (Shakouri, 2009). Using trade to help mitigate the effects of a drought occurred when some countries in SAPP experienced severe power shortfalls in 2019. The driest rainy season in the Lake Kariba catchment area since 1981 reduced hydro generation from the Kariba dam on the Zambia-Zimbabwe border, leading to power outages of up to 4 hours per day in Zambia and 18 hours per day in Zimbabwe (USDA, 2019; Hill, 2019; Hill and Ndlovu, 2019). Zimbabwe turned to increased imports from Mozambique partially to offset its own electricity shortages (ZimLive, 2019).

The possibility to trade has reduced the need for generation reserves in the region allowing economies of scale to be captured (ECA, 2009). A stable power system must balance the quantity of electricity injected into the grid with that taken off the grid within very short timescales of less than a second at all times. To do this, power systems hold some capacity in reserve, including as spinning reserve, to allow generation output levels to be changed very quickly. Other reserves are held in the form of back-up capacity or standing reserve that are called upon in longer timescales, for example, during a dry hydrological year, to replace generation that is out for maintenance or to meet higher than expected demand. ECA (2009) reports that a decision to share spinning reserves in the SAPP region reduced the national requirement for holding spinning reserve from 20% to 15% of peak demand. With the current peak demand of 50,775 MW in SAPP in 2018/19 (SAPP, 2019), this implies avoided generation capacity of over 2,500 MW. Similarly, trade could reduce the amount of standing reserve required by each country. We apply a generation capacity requirement in the planning model that reflects the need for a power system to have standing reserves and spinning reserves and explore the effect of allowing interconnector import capacity to contribute towards meeting this requirement.

Electricity trade also helps to provide security of electricity supply (Castagneto Gissey et al., 2019). If the availability of imported electricity is uncorrelated with the availability of domestic supply sources, the portfolio effect means that the variation of the availability of supply overall (including imports) is lower than the variation of availability of any one supply source.

Trade can also help countries in the region to reduce greenhouse gas emissions in two ways. Firstly, interconnected power systems enable greater penetration of intermittent renewable generation, which produce less greenhouse gases than conventional generation (SAPP, 2017). Secondly, trade may also facilitate a country's policy to reduce greenhouse gas emissions. South Africa, for example, has traditionally relied on coal fired generation as a cheap source of power, a source that produces significant levels of carbon dioxide ($CO_2$). In 2019, South Africa developed a plan for its power sector to 2030 that takes into account its Paris Accord obligations (UNFCC, 2016) among other considerations, with the plan including the import of 2,500 MW from the Grand Inga hydro generation project in DRC (SA IRP, 2019). Although our research focusses on the effects of trade on costs we do also report the effect of trade on greenhouse gas emissions.

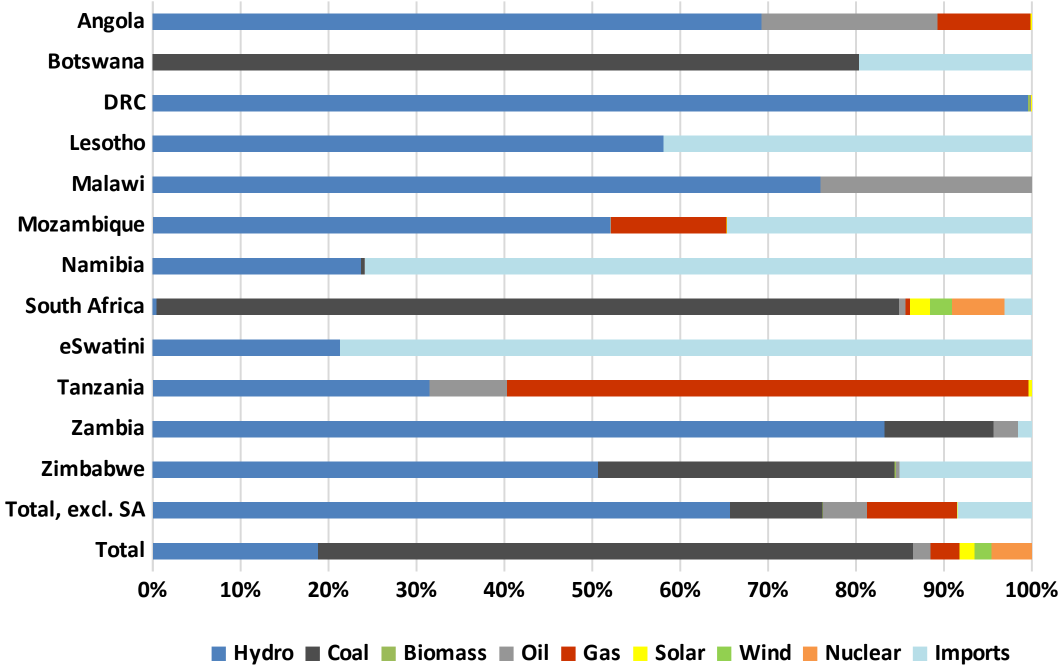
*Current status of power trade in the SAPP region*

Power exchange between countries in SAPP is currently very limited with only 6,362 GWh exchanged in 2018/19 (SAPP, 2019)[47], representing under 2% of the system load of SAPP countries. Currently, the majority of this trade (68% or 4,308 GWh) is through bilateral contracts agreed from time to time between the utilities of SAPP. The remainder of the traded volumes (32% or 2,054 GWh) was traded on what SAPP calls the competitive market, consisting of a Day Ahead Market, Intra-Day Market, Forward Physical Monthly Market and Forward Physical Weekly Market (SAPP, 2019). While there are some transmission constraints in the region, as evident from the difference between volumes matched and volumes traded on the Day Ahead Market (SAPP, 2017; SAPP, 2018; SAPP, 2019), transmission constraints do not fully explain the low volume of trade in the region.

While the volume of power trade in the region is limited, for some countries imports represent a significant share of the country's current generation mix (**Figure 9**). This is the case for eSwatini (imports were about 79% of system load in 2018), Namibia (76% share), Lesotho (42%), Mozambique (35%), Botswana (20%) and Zimbabwe (15%).

[47] Further to the traded volumes reported in the SAPP Annual Report, we note that Hidroeléctrica de Cahora Bassa (HCB) of Mozambique sells most of its output to Eskom of South Africa through long term contracts, selling over 8,320 GWh to Eskom in 2018, 8,447 GWh in 2017 and 9,025 GWh in 2016 (HCB, 2018). In turn, Eskom sells each year approximately 7,650 GWh to the Mozal aluminium smelter located in Southern Mozambique (SAPP Pool Plan, 2017). Adding these two transactions to the trade volumes reported by SAPP brings total trade in the region in 2018 to about 22,332 GWh (6.7% of the system load). We note that the reporting period of the SAPP Annual Reports is not a calendar year but the period April to March.

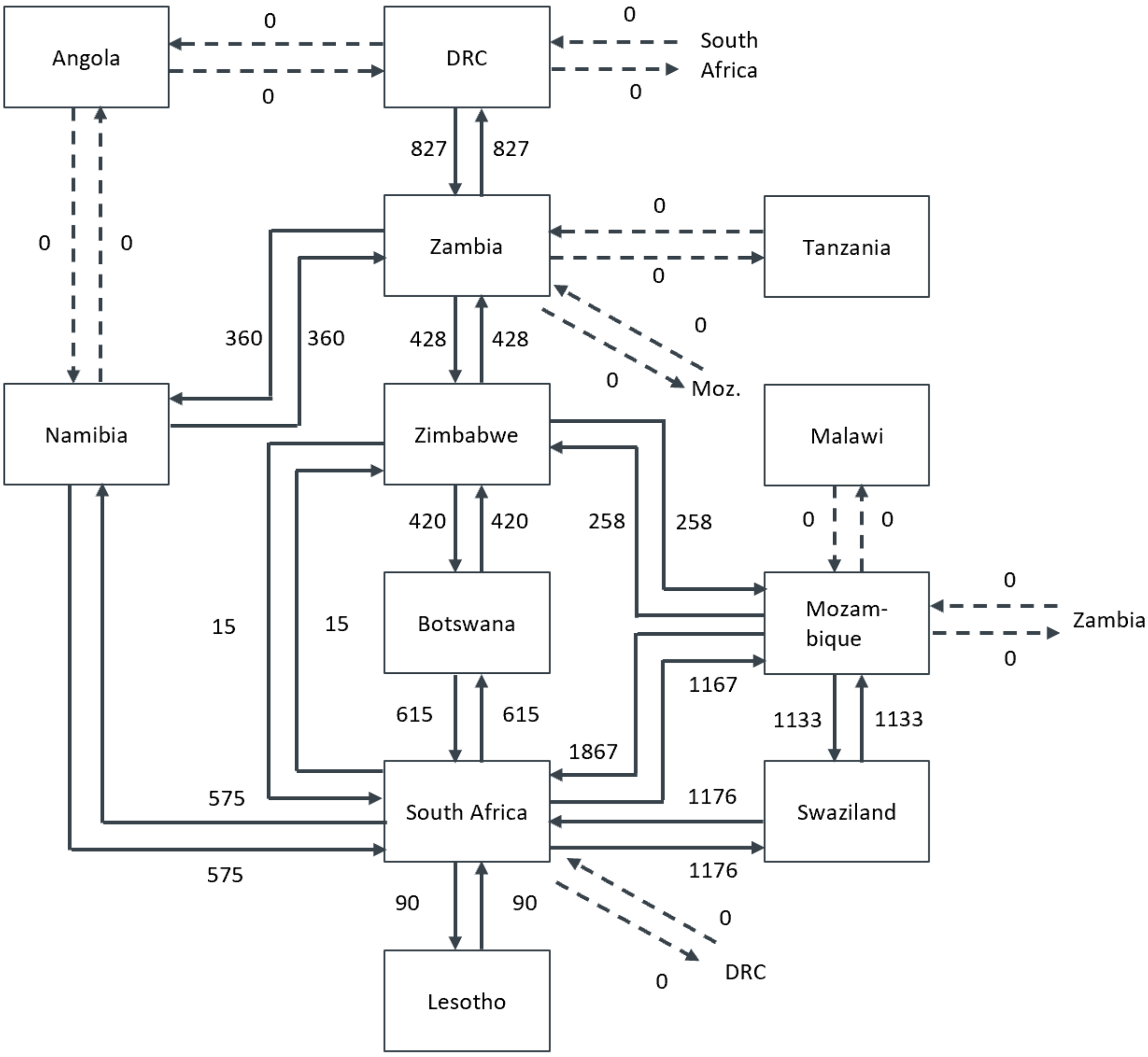
**Figure 9: Current power generation mix (2018)**




*Source: Authors based on Rocky Mountain Institute (2019), BPC (2018), EEC (2018), EEC (2019), Eskom (2019), LEC (2018), LEC (2019), NamPower (2018), ZESCO (2017), ZETDC (2018), AFREC (2018), GlobalPetrolPrices (2020).*
*Note: This represents the generation mix of the SAPP members. Imports in the 'Total, excl. SA' category are imports from South Africa to the remaining countries in the SAPP region. We do not show the limited imports to Tanzania from Uganda and Zambia.*

**Figure 10** shows the electricity transfer capacity for the SAPP region, including for planned new interconnections with Angola, Malawi and Tanzania, which is indicative of the upper limit on the potential to trade electricity in the region using existing infrastructure. Transfer capacity is derived from the capacity based on the thermal limits of transmission lines reduced for other constraints on the amount of electricity that can flow between countries related to the voltage and stability of the power system. For this reason, transfer capacity is significantly lower than thermal capacity for most lines as shown by SAPP (2020).

**Figure 10: SAPP countries and their current interconnector transfer capacities (MW)**




*Source: Authors based on SAPP (2020), JICA (2018b), World Bank (2018b).*
*Note: Paths shown as dashed lines represent interconnector projects joining new country pairs that have been identified but not yet developed.*

Clearly the SAPP region does not currently fully utilise the available transfer capacity to trade electricity between countries. Annual trade of 6,362 GWh (or 22,332 GWh if we include the sale of power from HCB to Eskom and the sale of power from Eskom to Mozal) is the equivalent to only 725 MW (or 2,550 MW) of continuous flow throughout a year, far below current transfer capacity in the region of over 7,700 MW. This suggests that constraints not solely related to the transfer capacity of the interconnectors between countries are limiting trade, or that economically speaking the efficient level of trade is low. Other limitations to trade in the region relate to the inability of financially weak utilities to pay for electricity imports (e.g. ADB, 2019; Mukeredzi, 2019), and policies aimed at countries being self-sufficient with respect to generation. For example, Zimbabwe has struggled to pay for electricity imports in the past, limiting its ability to import additional electricity to help meet demand, including during the dry year of 2019 (Kuyedzwa, 2020). Self-sufficiency is a requirement under the SAPP, with the SAPP Pool Plan (2017) describing the SAPP's generation planning criteria as including a long-term objective for each country to have sufficient generation capacity to meet its peak demand. However, the SAPP does allow countries to meet their capacity requirement at any one time through firm contracts to import electricity.

Increasing trade among SAPP countries and thereby unlocking the benefits from trade would require a reduction in barriers to trade that are unrelated to existing transfer capacity, including a lack of payment discipline, lack of security of supply, and a lack of trust (World Bank, 2018a), and investments in new physical interconnection to create additional transfer capacity. Several studies have shown that benefits from international power trade outweigh the investment requirements associated with new interconnectors (for example, IRENA, 2013). Castellano et al. (2015) find that increasing regional power trade could save US$ 41 billion or 4.9% of the overall CAPEX required to achieve 70-80% access by 2040 in SSA. Timilsina and Toman (2016) find that in South Asia the benefits of increasing regional electricity trade outweigh the costs five times.

# 4.3. Methodology and data

## 4.3.1. Overview

We calculate the forward-looking cost of generation investments and operation and the forward looking cost of transmission interconnector investments in meeting the forecast demand for electricity on the main grid in the SAPP region over the period 2019 to 2030. The benefit of trade is estimated as the difference between the present value of costs under the no trade state of the world and one of several states of the world with trade:

- *No trade (S1)*. A country's demand for electricity over the period 2019 to 2030 is met solely using generation assets located within the national boundaries of the country, with no opportunity to trade electricity between countries; and
- *Trade current*. The same level of demand over the period 2019 to 2030 is met using generation assets located within the national boundaries of each country while allowing for opportunities to trade electricity among countries using only the existing transmission interconnectors between countries, where trade flows

are determined by the optimisation model. When considering trade across existing interconnectors we look at two scenarios:

  - *Trade current no contribution (S2a).* Interconnector import capacity does not contribute towards meeting a country's requirement to have a margin of firm supply capacity above peak demand.
  - *Trade current contribution (S2b).* Interconnector import capacity contributes towards meeting a country's requirement to have a margin of firm supply capacity above peak demand.

- *Trade current and new (S3)*. We allow for trade using both the existing transmission interconnectors between countries and any additional transmission interconnectors to be built between countries, if economically beneficial to do so as determined by the optimisation model. Both existing and new interconnector import capacity contribute towards meeting a country's requirement to have a margin of firm supply capacity above peak demand.

In addition to understanding the benefits of trade in lowering the costs of supply, we are also interested in how trade could affect the cost of providing on-grid access and supply of electricity to currently unelectrified households. Therefore, when constructing the demand to be met in the trade and no trade scenarios, we consider three different access targets:

- *No new household connections*. Under this scenario we assume no incremental household connections, such that future consumption is equal to the consumption of currently connected households and the consumption of non-residential customers and their development over time.
- *Current rate of progress*. This scenario assumes consumption as above plus the consumption of new household connections, where the number of new household connections each year equals the rate at which households were gaining access in the recent past in each of the twelve countries.
- *Universal access target*. Here we assume the target of universal access to electricity is reached by 2030 in all twelve countries regardless of their access starting point or their recent progress in increasing access. This scenario is in line with the current universal access target enshrined in SDG 7.

This means that we look at twelve scenarios in total, which vary according to the strength of interconnection between countries and the electricity access target to be achieved by 2030. In addition to the present value of costs of generation and interconnection, we also compare the levelised cost of electricity (LCOE) for providing access under the different trade scenarios, where the LCOE relates only to wholesale costs of electricity. The LCOE for providing access is calculated as the change to the sum of discounted costs when additional access is provided, divided by the change to the sum of the discounted quantities of electricity supplied when the additional access is provided. To calculate the present value of costs and the LCOE, we use a real discount rate of 6% in line with SAPP Pool Plan (2017). We also look at different sensitivities to better understand drivers of the benefits of trade and the robustness of our results, including three sensitivities with no Grand Inga, a drought and a higher discount rate.

## 4.3.2. Methodology

At the heart of our analysis is a least-cost generation and interconnection expansion model that estimates the overall forward-looking generation costs and interconnector expansion costs subject to meeting the load forecast over the planning horizon. The least cost power system expansion model is the same as the one used in Chapter 3 extended to allow endogenous decisions about cross border interconnector investments. Here we provide an overview of the constraints imposed on the decision variables and of the decision variables themselves. **Annex 7** provides the core code of the model that defines the equations and variables used in the optimisation. A mathematical formulation of the model (without endogenous interconnector investment decisions) is provided in **Chapter 3**.

The mixed integer programming optimisation model takes decisions about the operation and investment of countries in generation and interconnectors within the SAPP region, with the optimisation criterion being the lowest present value forward looking cost over the planning horizon (i.e. 2019 to 2030). Economic costs and a social discount rate are used such that decisions are taken so as to minimise economic costs, i.e. costs without subsidies or taxes.[48] The model considers various decision variables and constraints to proxy power system operation and planning. Constraints on the decision variables in the model include:

- *Supply and demand balance constraint*. Domestic supply plus imports (where imports are the neighbouring countries' export flows adjusted downwards for interconnector losses) minus exports and plus load not served must equal

[48] However, we do not apply the economic cost of generation externalities such as the cost of local ($NO_x$ and $SO_x$) or global ($CO_2e$) pollutants.

domestic demand in each hour and each country. Load not served would arise if there is insufficient available capacity either provided by domestic generation or through interconnectors.

- *Security of supply constraint*. This constraint requires the system to have firm generation and transmission import capacity (in the applicable trade scenarios) equal to 105% of peak demand in place each year to be able to withstand incidents and provide reliable supply. If this constraint is not met, the country faces a penalty for any capacity shortfall. A capacity requirement is needed in a planning model such as this one because the model understates real world volatility and uncertainty in demand and generation availability. With no security of supply constraint, the model would make a trade-off between operating costs (including the cost of load not served) and fixed costs when deciding whether to build new capacity. Since understating volatility and uncertainty tends to understate load not served, which has a very high unit cost, too little capacity would be built, leading to estimated wholesale costs that are too low. The security of supply constraint and the supply and demand balance constraint interact such that the quantity of capacity shortfall is inversely correlated with the quantity of load not served. We note that a reserve margin is also needed in the real world to take into account of uncertainty and variability of both supply sources and demand, including the need for the system to cope with sudden changes in supply-demand balance.
- *Energy resource constraints*. This constraint reflects the natural energy endowments and the ability to import primary energy resources to use for electricity generation of each country, represented as the maximum quantity of a particular primary energy type (e.g. coal, gas, heavy fuel oil, diesel, biomass, hydro, wind, solar, geothermal, uranium) able to be consumed in a given year by each country.
- *Generation characteristics*. Two constraints representing generation characteristics are the maximum output in an hour from each power station, and the maximum capacity of each possible type of power station that could be built.
- *Transmission constraints*. Each transmission interconnector between two countries has a maximum flow in MW in each direction, equal to the transfer capacity of the interconnector. Possible new entry interconnectors are limited to specific pre-identified projects with the choice of whether or not to build an

interconnector being a binary decision (i.e. build or do not build) in a year. Once built, a new interconnector is part of the system until the end of the forecast period.

The decision variables in the model include:

- *Generation output*. The quantity of electricity produced (MW) by each power station in each hour.
- *Generation investment*. The quantity of new generation capacity (MW) to build in each year for each candidate new power station. This is represented as a continuous variable in the model although in practice there would be a range of discrete possibilities for the size of a new power plant.
- *Generation closure*. For existing power plants, the quantity of existing generation capacity (MW) to close in each year. The optimisation model is free to close an existing power plant and would choose to do so if the savings from avoiding the annual fixed O&M cost exceeded the additional costs of closing the plant (e.g. additional fuel costs of other power stations, additional loss of load costs, fixed costs if additional capacity is needed and any increase in the cost of not meeting the capacity requirement).
- *Loss of load*. The quantity (MW) of energy not served in each country and each hour, which given the high cost associated with loss of load, would only be used if there were insufficient generation and interconnector capacity to meet demand and it were more costly to build and run new capacity than not to serve the load. We set the value of lost load to 1,000 US$2018 per MWh, which is also the cost of unsevered energy used by SAPP Pool Plan (2017).
- *Capacity violation*. The extent (MW) to which the capacity requirement in each country is not met in each year. We set the value of having insufficient capacity to 1,000 US$2018 per kW in each year, which is above the annuitized cost of new capacity so as to encourage the security of supply constraint to be met.
- *Interconnector flow*. The quantity (MW) of flow on each interconnector between two countries in each hour and in each flow direction.
- *Interconnector investment*. Whether or not (0 or 1) to build each new candidate transmission interconnector in each year, where an interconnector can only be built once.

The objective function value is the present value of costs as at 2019, including the following cost components:

- *Generation fuel costs*, which vary with the quantity of electricity produced by power station in each hour.
- *Generation variable operation and maintenance costs*, which also vary according to power station output.
- *Generation fixed operation and maintenance costs*, which vary with annual installed capacity by power station.
- *Generation investment costs*, which vary with new build capacity by power station, represented as an annuity over the lifetime of a new power station and where only the sum of the annuity until the end of the planning horizon (2030) is included in the objective function. By taking a truncated sum of the annuity we avoid biasing investments towards the earlier years of the planning period.
- *Transmission investment costs*, which vary with new build capacity by interconnector, represented as an annuity over the lifetime of a new interconnector and where only the number of years in the annuity up to the end of the planning horizon (2030) is included in the objective function.
- *Value of lost load (VoLL)*, which varies with the quantity of energy not served in a country in each hour.
- *Cost of insufficient capacity*, which varies with the shortfall of capacity relative to the capacity requirement in each country and in each year.

### *4.3.3.* Supply Side Data

The volume of data needed for this study is extensive. Each of the twelve country power markets is represented by a supply and demand side. On the supply side, the key data entering the least-cost optimisation model include:

- *Existing and committed power plants*, each represented by: its country of location, permanently de-rated installed generation capacity, planned and forced outage rates, commissioning date, planned decommissioning date, fuel type and specific fuel consumption (heat rate) when relevant, non-fuel variable and fixed operating and maintenance costs, availability profile for renewable generation, and for each new power plant its capital cost and expected economic life.
- *Candidate power plants*, described in terms of potential generation options that could be developed in each country, comprising either project specific candidate

plants (new hydro and geothermal plants) or generic candidate plants that get built so as to meet the forecast load and to replace old power plants when they close. The data required for candidate power plants are the same as for existing and committed power plants. Furthermore, we limit the amount of generic power plants that can be built each year to reflect the country's ability to mobilise resources.

- *Existing and candidate transmission interconnectors*, represented by existing transmission capacity between two countries and interconnector losses, and for new interconnector projects the earliest possible commissioning year, capital costs and economic lives. The earliest possible commissioning year is obtained from various sources including the SAPP Pool Plan (2017), utility websites and power sector master plans. **Annex 5** summarises the current transfer capacities in the SAPP, including all possible future interconnector projects in the region. The interconnector investment options that we consider in the model are those set out in the SAPP Pool Plan (2017). In other words, we use identified projects although the projects may well be at inception stage before detailed environmental and social studies have been carried out.[49]
- *Fuels*, represented by fuel costs and fuel availability in each country, either from domestic fuel sources or from imports.

The model begins with each country's existing generation fleet and interconnector assets as at 2018. These data, together with already committed power plant projects and power stations already under construction, were obtained from African Energy (2019). Interconnector transfer limits were obtained from SAPP's website (SAPP, 2020) and candidate interconnector projects and their characteristics from SAPP Pool Plan (2017). We complemented these data with data available in utility annual reports, power sector master plans and SAPP annual reports and, since we are interested in grid generation only, we exclude generation embedded within end user sites and off-grid generation.

We treat existing power plants as being fixed in place, with no additional investment costs other than refurbishment costs when relevant. That is, the only costs for existing power plants are operating and maintenance costs and fuel costs. Existing interconnectors are treated similarly, with no direct costs associated with them. However, we do assume

[49] We note that the ability to develop new transmission is affected by environmental factors in addition to financial considerations as to the costs of developing the interconnector capacity. Thorough feasibility studies as well as environmental and social impact analysis need to be undertaken before any decision on new interconnection is made, as well as a cost-benefit analysis that would try to quantify the overall economic costs and benefits of the project (e.g. emission costs, costs of relocation of people if needed, impact on habitats, etc.). We expect that some of the identified projects could face insurmountable barriers to development and conversely other projects or alternative routes for identified projects could be identified.

that some electricity is lost when it flows along an interconnector such that the quantity of electricity exported from a country is greater than the corresponding quantity of electricity imported by the destination country.

Similar to the methodology in Chapter 3, because the level of demand in the scenario where no incremental household connections are considered is likely to be below the level of demand forecast by utilities and on which new power station commitments are based, we treat committed generation projects as candidate projects. This gives the model the flexibility to optimise the generation fleet to the level of demand without overstating the costs of serving existing customers. Conversely, we also consider scenarios where demand is likely to be higher than the level forecast by utilities (100% access by 2030 and no trade, where each country must build its own generation capacity to meet demand). To allow the model the flexibility to optimise generation developments and not to dominate the results by the VoLL, we allow committed and candidate generation projects (with the exception of candidate hydro generation projects) to be developed before they could be developed in practice due to project lead times.

An overview of the data feeding into the least cost expansion model is provided in annexes: **Annex 4** provides generation input data and **Annex 5** provides existing and candidate interconnector transfer capacities for the region considered in our analysis.

### *4.3.4.* Demand for Electricity

A comprehensive electricity demand forecast is essential for adequate power sector planning from which requirements for generation capacity, including the reserve margin, technological mix, maintenance planning and the need for new interconnection capacity can be assessed. Overstating demand in the forecast could lead to excess generation capacity and a non-optimal level of interconnection capacity being built, leading to unnecessary costs, while understating demand could lead to suppressed demand. There is significant uncertainty as to future electricity demand and a possible systematic forecast bias, which is evident from past demand forecasts overshooting, resulting in electricity demand forecasts being revised downwards, largely attributed to lower than expected economic growth.[50] Furthermore, uncertainty as to future demand is currently being aggravated by the ongoing health crisis due to Covid-19, where several countries have

[50] For example, South Africa's 2010 Integrated Resource Plan (IRP) estimated demand of 450 TWh by 2030, which was subsequently revised downwards to 350 TWh in the 2016 IRP (SA IRP, 2016), and further down to 310 TWh in the 2019 IRP (SA IRP, 2019). Similarly, for Malawi, demand was revised downwards in its most recent Integrated Resource Plan (Norconsult, 2017).

seen demand fall by 20% or more due to lockdowns, and changes to daily demand profiles (IEA, 2020b).

To derive a demand forecast for every year of the forecast horizon (i.e. 2019 to 2030), for each country we model separately i) consumption of non-residential customers, ii) consumption of existing residential customers, and iii) consumption of newly connected residential customers. To do this, we follow the same approach as in Chapter 3 and derive on-grid consumption of existing residential and non-residential customers of 299 GWh and sent-out demand of 332 TWh for the year 2018 for the region. We then apply a 4% annual growth rate in consumption for non-residential customers and a 2% annual growth rate for those residential customers that are already connected to the grid for all countries in the region, with the exception of South Africa for which we assume a 1.8% annual growth rate for both residential and non-residential customers in line with SA IRP (2019). This translates to a 2.1% growth in consumption in the region and to a 3% consumption growth if South Africa is excluded from the SAPP average over the forecast horizon, and excluding consumption stemming from any incremental household connections.

Following the same approach as in Chapter 3 and assuming that on-grid access constitutes the least cost option for households in urban areas and for 30% of households in rural areas in line with OECD/IEA (2017), meeting the universal access target by 2030 implies that 38.4 million households would need to be connected to the grid over the forecast horizon. The number of households to be connected under the 'Current rate of progress' is considerably lower and corresponds to 10.3 million new on-grid household connections over the period 2019 to 2030. Regarding consumption of those newly connected, we assume households that gain access to electricity will consume 500 kWh/annum in urban areas and 250 kWh/annum in rural areas in the first year of connection (in line with OECD/IEA, 2017), with their consumption increasing by 4% per annum over the forecast horizon. We note that households are assumed to be connected progressively over time, with the same number of households assumed to be connected in each year over the forecast horizon.

The resulting incremental consumption in the SAPP region due to new household connections is a little over 8,000 GWh in 2030 under the current rate of progress and 32,000 GWh with universal access by 2030.[51] The incremental on-grid consumption due

[51] We note that this is the same demand forecast as that derived in Chapter 3 under S1 (Current rate of progress) and S3 (Universal access).

to new household connections is estimated at 6,441 GWh in 2030 under the current rate of progress and increases to 24,011 GWh with universal access by 2030. With this incremental load, on-grid electricity consumption is forecast to grow on average between 2.3 and 2.6% per annum in the forecast period (3.3 and 4.6% if SA is excluded from the SAPP average), with the higher estimate corresponding to the universal access target. Country-level detailed demand data and their development over the forecast horizon are provided in **Annex 6**.

The assumed growth corresponds to an electricity consumption elasticity with respect to national GDP of between 0.87 and 1.01 in the SAPP region, with the lower estimate corresponding to the current rate of progress and the higher estimate corresponding to the universal access target.[52] This demand forecast broadly corresponds to the low-case scenario in the SAPP Pool Plan (2017), which forecast 2.4% annual growth in sent-out demand across SAPP countries over the period 2018 to 2030 (the base case scenario assumes an annual growth rate of 3.7%, which however, seems overly optimistic with actual demand being considerably below the SAPP Pool Plan (2017) forecast).

## 4.4. Results and discussion

Using a least-cost optimisation model for the SAPP region, we estimate the net present value forward looking wholesale cost, in terms of generation investment and operating costs and new interconnection investment costs, over the period 2019 to 2030 for different trade and electricity access scenarios. We show that without the ability to trade electricity, and therefore with each country having to rely solely on its own generation resources, the cost of supply is greatest across all of the electricity access scenarios (scenario S1). However, if countries can efficiently use existing interconnector capacity to trade electricity (scenario S2b), the total cost of supply to 2030 falls significantly, by 8.1 US$2019 billion for the status quo level of access and by 8.2 US$2019 billion for universal access by 2030. This represents a cost reduction of 5.2 – 5.4% compared to the scenario with no trade. Indeed, unless countries find a way to come together to coordinate the development of the very large transmission projects

[52] We relied on the October 2020 edition of the World Economic Outlook Database (IMF, 2020) to calculate the CAGR of the weighted average real GDP growth rate for the region over the period 2018 to 2030. Since the data in the World Economic Outlook Database goes only up to 2025, we took the average of the last three years for which forecast data were available when forecasting the real GDP growth rate beyond 2025, except for Mozambique. For Mozambique, the World Economic Outlook Database forecasts GDP growth of over 11% for the years 2024 and 2025. While this growth rate could reflect commercialization of natural gas resources in Mozambique, we do not take the view that such a high growth rate is sustainable in the longer term and, therefore, we relied on the simple average real GDP growth rate over the period 2010 to 2019 to represent the growth rate beyond 2025 in Mozambique.

required to capture the benefits of lower cost hydro generation projects in the North of the SAPP region, this might be indicative of the extent of benefits from trade. **Table 12** provides a summary of the forward-looking generation costs under the different trade and access scenarios.[53]

**Table 12 Total forward-looking cost of supply under different trade and access scenarios**

| Total cost (US$2019 million) | No trade (S1) | Trade current no contribution (S2a) | Trade current contribution (S2b) | Trade current and new (S3) |
|---|---|---|---|---|
| **No incremental household connections** | 151,147 | 148,222 | 143,002 | 142,402 |
| **Current rate of progress in connecting new households** | 152,647 | 149,723 | 144,470 | 143,858 |
| **Universal access target achieved by 2030** | 157,134 | 154,384 | 148,956 | 148,143 |

*Source: Authors.*
*Note: We are interested in the forward-looking generation and new interconnection investment costs, which are only those costs affected by future decisions about generation and interconnector investments and operations that best meet future consumption needs. When estimating the forward-looking generation and new interconnection investment costs, the investment costs of the existing generation fleet are not included because they are sunk costs that are unaffected by future decisions about generation and interconnector investments and operations. We do, however, include the annual fixed O&M, variable O&M and fuel costs of both existing and new power plants along with the investment costs of new power plants and new interconnectors. This means total wholesale costs for each scenario will be higher than the costs we report since on top of forward-looking costs, utilities need to service their existing debt and pay capacity charges to existing independent power producers (IPPs). We note, however, the amount of sunk costs stemming from existing generation is the same across all scenarios.*

As noted previously, annual cross border trade in the SAPP was 6,362 GWh in the financial year 2018/19. We estimate that the economically efficient level of trade using existing interconnector capacity is around 24,000 GWh (increasing to 50,000 GWh in 2030 with 100% access).[54] This implies that the SAPP region presently does not use the current transfer capacity efficiently, suggesting that not all of the possible reductions in wholesale costs of supply from trade using existing interconnector capacity are being captured in the region. Indeed, the SAPP region currently appears to be closer to the no trade scenario than to efficient trade with existing interconnectors.

If countries not only utilise existing interconnectors but also build and utilize new interconnectors when efficient to do so (S3), the total forward looking wholesale costs would fall even further compared to no trade, by 8.7 US$2019 billion for the status quo level of access and by 9.0 US$2019 billion for universal access by 2030. This suggests that the benefit of trade is greatest under the universal access scenario. This result is intuitive since as demand increases, the marginal cost of electricity tends to rise, and

[53] SAPP Pool Plan (2017) reports the present value forward looking cost of generation and transmission investment to 2040 as $241 billion in their full integration scenario, excluding loss of load costs. Extending our forecast horizon to 2040, would increase our estimated forward looking costs to approximately US$ 230 billion to US$ 250 billion depending on the access scenario.

[54] We note that the level of trade reported by SAPP appears to exclude the power flows from HCB to Eskom and the flows from Eskom to Mozal in Mozambique. For modelling purposes, we assume each country is a copperplate. This allows Mozal to be supplied directly by Hydro Cahora Bassa (HCB) and other power stations located in Mozambique rather than for HCB to export the bulk of its output to South Africa and for Mozal to import its supply from South Africa. This means that the trade flows in our model are comparable to the current 6,362 GWh of trade reported in the SAPP annual reports.

therefore the marginal benefit of trade is also likely to increase with higher demand. This represents a cost reduction of around 5.7 – 5.8% compared to the scenario with no trade. While similar to the finding of Rosnes and Vennemo (2009) that allowing full trade brings a net saving of 5.6%, we note that they compare full trade to trade using existing interconnectors as at 2005 rather than to no trade. Similarly, Graeber et al. (2005) found that optimising generation and transmission investments in the SAPP region would bring savings of between US\$1999 2.2 – 4.0 billion (approximately US\$2019 3.4 – 6.13 billion) over the period 2000-2020 or at least 5% of total system costs. Our findings are greater than Graeber et al. (2005) although we note that their trade scenario is compared to a scenario with restricted trade that places country specific limits on imports as a share of demand and country specific capacity requirements to be met from domestic generation rather than to no trade.

We considered a further scenario (S2a) where existing interconnectors may be used for economic trade but, unlike scenario S2b or scenario S3, interconnector import capacity does not contribute to meeting a country’s capacity requirement. This is similar to the current SAPP planning criteria whereby countries are expected to have sufficient domestic generation capacity to meet peak demand plus reserve requirements. In this case we found that costs are 1.8 – 1.9% lower than with no trade, implying that about 65% of the possible cost saving from using existing interconnector capacity efficiently relates to efficient sharing of reserve capacity between countries.

Our findings imply that most of the benefits of trade could be captured through efficient use of existing interconnector capacity as at 2020, and that a smaller incremental net benefit relates to building new interconnector capacity in the SAPP region. However, importantly, almost two-thirds of the benefits of efficient trading on existing interconnectors are lost unless countries share reserve capacity allowing them to rely on interconnector import capacity to help meet their firm capacity requirements. These results are summarised in **Table 13**.

**Table 13 Change in total forward-looking wholesale cost under different scenarios**

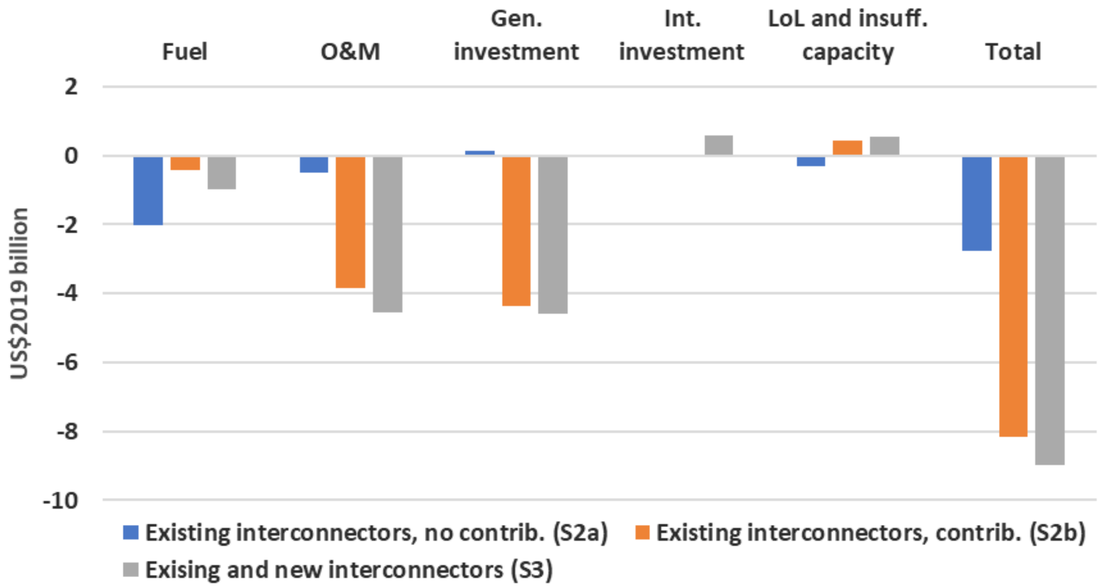
| Savings in costs for the period 2019 to 2030 (US$2019 million and relative to no trade) | Trade current no contribution (S2a) | Trade current contribution (S2b) | Trade current and new (S3) |
|---|---|---|---|
| No incremental household connections | -2,925 (-1.9%) | -8,145 (-5.4%) | -8,745 (-5.8%) |
| Current rate of progress in connecting new households | -2,924 (-1.9%) | -8,177 (-5.4%) | -8,789 (-5.8%) |
| Universal access target achieved by 2030 | -2,750 (-1.8%) | -8,178 (-5.2%) | -8,991 (-5.7%) |

*Source: Authors.*

Looking at the effect of trade on the different cost components in the sector helps to show how trade reduces costs. With the ability to trade, the cost of fuel, operations and maintenance and generation investment all fall in the region taken as a whole. In the case where interconnectors do not contribute towards the capacity requirement (S2a), the cost of unserved energy falls as more domestic generation capacity is required to meet demand in addition to neighbouring countries providing mutual support to meet demand. However, in the case where interconnectors do contribute towards the capacity requirement (S2b and S3) there is a small increase in the cost of energy not served, which is partly offset by the reduction in the cost of having insufficient capacity available to meet reserve requirements and more than offset by a large reduction in new generation investment costs. The increase in the cost of energy not served is due to the interconnectors reducing the capacity requirement left to be met by generation in each country and with less generation on the system, the likelihood of there being some loss of load increases. Interconnector investment costs also increase, in the case where new interconnector investment is allowed.

These results are summarised in **Figure 11** for the scenario with universal access by 2030, with the blue and orange bars showing the change in costs for trade using existing interconnectors and the grey bars showing the change for trade using existing and possible future interconnectors under. We note that the pattern of change in the different cost components is similar across the different access scenarios.

**Figure 11: Change in present value costs compared to no trade – universal access by 2030**



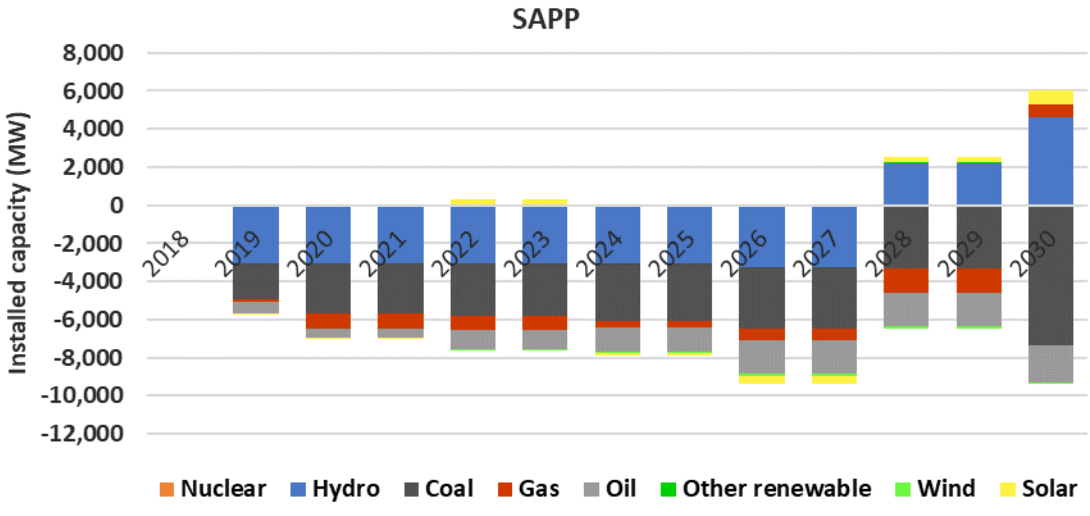

*Source: Authors.*
*Note: "O&M" refers to operating and maintenance costs. "Gen. investment" refers to generation investment costs. "Int. investment" refers to interconnector investment costs. "LoL and insuff. capacity" refer to the cost of energy not served and the cost of not meeting the capacity requirement. "Existing interconnectors, no contrib. (S2a)" refers to existing interconnector import capacity not contributing to the capacity requirement of the importing county. Detail on forward-looking wholesale cost and the change in present value costs under different trade and access scenarios is provided in* ***Annex 8****.*

As discussed above, the generation investment and maintenance costs fall with increased trade since trade allows less generation capacity to be built while meeting demand and security of supply requirements. Over the whole SAPP region, by 2030 we estimate that 3,330 MW less generation capacity would need to be built with full trade than without trade, while meeting the same level of demand – in this case universal access by 2030. Of the 3,330 MW reduction in generation capacity with full trade, most (about 2,200 MW) is related to allowing import capacity to contribute to capacity requirements and the remainder relates to other forms of generation optimization. Most of the reduction in net generation capacity is related to avoided coal fired generation capacity (7,330 MW by 2030), particularly in South Africa and Zimbabwe, and avoided oil fired generation capacity (1,950 MW by 2030).

On the other hand, more hydro capacity is developed elsewhere in the region, particularly in DRC and Mozambique (4,610 MW by 2030), more solar PV (780 MW by 2030) and more gas fired generation capacity (660 MW by 2030). The overall increase in hydro and solar PV generation capacity with trade makes sense when one considers that trade will help countries to manage intermittent renewable generation such as solar PV and to manage hydro generation with its seasonal river flows. Although we model the output of solar and wind variable renewable energy (VRE) sources as deterministic profiles (not stochastic profiles), the profiles do show variation from hour to hour, day to day, and country to country. Therefore, the ability to trade electricity between countries does help the regional power system to manage the modelled VRE output in each country. However, we recognize that our model tends to understate volatility in VRE output, and therefore is likely to understate the benefits of trade for the development of renewable generation. Trade also helps countries such as Mozambique, Namibia and Angola to unlock their indigenous gas resources and develop more gas fired generation capacity.

We also see a regional shift in the development of generation capacity with trade, with less capacity developed in South Africa (12,155 MW less capacity by 2030) and more capacity developed elsewhere (8,825 MW more capacity by 2030). As such, South Africa increasingly imports power to meet demand, reflecting the cheaper generation options available outside the country. Most of the additional net capacity is developed in DRC (3,900 MW more capacity by 2030), Namibia (1,880 MW more capacity) and Mozambique (4,970 MW more capacity). These results of the impact of trade on the net cumulative generation capacity are shown in **Figure 12**. We note that our results are similar to Taliotis (2016) who finds increased hydro generation and decreased coal generation in Southern Africa with trade.

**Figure 12: Change in net generation capacity for trade compared to no trade (2018 – 2030)**




*Source: Authors.*
*Note: The figure shows the difference between the installed capacity in the SAPP region for the scenario with optimal interconnectors less the scenario with no trade, assuming 100% access by 2030 in both cases. Results on the total generation capacity with full trade and no trade for the region, as well as country level results is provided in* ***Annex 8****.*

The scenario with optimized interconnection is intended to show the possible economic benefits of regional trade. However, overcoming policy constraints due to perceived or real security of supply issues is needed to capture those economic benefits.

For example, as South Africa decommissions ageing coal plants our modelling shows that it increasingly imports power to meet demand, reflecting the cheaper generation options available outside South Africa. In 2024, South Africa imports are equivalent to 5% of demand, 6% in 2026, 12% in 2028 and 18% in 2030. While South Africa's IRP 2019 includes 10,500 MW of old coal fired power station decommissioning and 2,500 MW of imported hydro from Grand Inga (DRC) by 2030, this implies less imported energy than shown by our optimized interconnection scenario. Even with this lower level of imports, the IRP 2019 raises security of supply concerns from imports along with the possibility of forcing into the plan new coal plants located in South Africa.[55]

Security of supply in the power sector can be thought of as the ability of the system to react swiftly to sudden changes in the supply-demand balance and to do so at an affordable price. When assessing security of supply, aspects that are commonly considered include diversity of the supply mix, reliance on imports, especially when imports are sourced from a single neighbouring country, and the impact of droughts for power systems that are reliant heavily on hydro generation capacity (IRENA, 2013). Equally, security of supply should also consider imports of primary energy sources used for electricity generation, the uncertainty and variation of other generation sources aside from hydro generation and the extent of any available generation capacity overhang relative to demand (Yue-wei Wu and Rai, 2017).

While there is no single indicator for energy security, several quantitative measures of diversity have been developed that reflect the three attributes of diversity: variety, balance, and disparity (Yue-wei Wu and Rai, 2017). Two commonly used measures of energy supply security are the Shannon-Wiener Index (SWI) and Herfindahl-Hirschman index (HHI), both of which measure only variety and balance. The SWI is the sum over all distinct supply options available of the share of each option multiplied by the natural log of the share of the option, with a minimum value of 0 (1 supply option) and an increasing value with diversity. The HHI is commonly used as a measure of market concentration by competition authorities[56] and is essentially the same as the SWI. HHI equals the sum of the squares of the shares of each supply option with the result multiplied by 10,000, with the index value approaching 0 when the system relies on many supply options and 10,000 when the system relies on a single supply option.

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[55] According to SA IRP (2019), SA does not envisage importing power from one source above its reserve margin. Based on the results of our optimisation model, imports to SA come from three different countries: DRC, Mozambique and Namibia. Indeed, reliance on a single neighbouring country for imports could raise concerns about security of supply.

[56] See, for example, EC (2004).

Chalvatzis and Ioannidis (2017) find that the correlation between SWI and HHI is 0.85 for "equally contributing options." This implies that we could use either index to measure the diversity of primary energy supply and we opt to use HHI. For the calculation of HHI, electricity generation from each primary energy source and imports from each neighbouring country are treated as a distinct supply option.[57] We calculate HHIs using gross generation plus imports over the year for each country. We note, however, that we treat all primary energy sources of the same type irrespective as to location within a country as having zero disparity and all primary energy sources of a different type as having 100% disparity. This may understate diversity, for example, gas fired generation near the Rovuma basin in Northern Mozambique has little in common with generation using gas from Temane towards the south of the country. Conversely, our measure may overstate the diversity for a country with significant internal transmission constraints. Therefore, the use of HHI here should be treated as an indicator of diversity and, importantly, how diversity is affected by trade.

**Table 14** shows the HHI diversity indicator for each SAPP country and for SAPP overall in 2020, 2025 and 2030 with no trade and with trade using existing and new interconnectors (under the scenario with 100% access in 2030). Here, the comparison of HHI is important rather than the absolute level of HHI and the results indicate that trade tends to increase diversity and diversity also tends to increase over time. In some countries, such as DRC, diversity tends to decrease with trade as a single type of generation (in this case hydro) is developed for the export market. This suggests that other measures such as the extent of supply overhang may be needed to measure the resilience of an exporting country's power system. It is also notable that South Africa's diversity increases with trade, suggesting improved resilience, albeit by relying on increased imports.

[57] The distinct types of generation technologies used for all countries are: nuclear, hydro, coal, gas, oil (comprising diesel and HFO), wind, solar, and other renewables (comprising geothermal and biomass, which are both small). Imports from each country are treated as a distinct supply option, for example, in South Africa imports from Botswana, DRC, eSwatini, Lesotho, Mozambique, Namibia, and Zimbabwe are treated as distinct supply options. The rationale here is that even if imports from one country are stalled, it is likely that the difference can be supplied from another exporting country.

**Table 14 Diversity of electricity generation in the SAPP region with and without trade**

| HHI | 2020 No trade | 2020 Trade using existing and new IC | 2026 No trade | 2026 Trade using existing and new IC | 2030 No trade | 2030 Trade using existing and new IC |
|---|---|---|---|---|---|---|
| Angola | 6,536 | 6,538 | 5,220 | 5,075 | 4,799 | 4,086 |
| Botswana | 9,868 | 5,324 | 9,615 | 6,421 | 8,069 | 3,995 |
| DRC | 8,006 | 7,936 | 5,048 | 4,624 | 5,952 | 8,694 |
| eSwatini | 4,809 | 5,534 | 5,262 | 8,963 | 3,988 | 8,784 |
| Lesotho | 3,150 | 3,486 | 3,876 | 3,806 | 4,498 | 4,298 |
| Malawi | 3,261 | 3,261 | 3,765 | 3,770 | 5,238 | 6,318 |
| Mozambique | 7,881 | 6,199 | 6,750 | 4,870 | 7,274 | 4,574 |
| Namibia | 4,568 | 3,026 | 5,410 | 7,211 | 5,120 | 6,369 |
| South Africa | 8,105 | 7,932 | 7,190 | 6,793 | 6,238 | 4,609 |
| Tanzania | 6,644 | 6,644 | 6,994 | 7,642 | 4,721 | 4,816 |
| Zambia | 5,867 | 4,321 | 4,732 | 3,572 | 5,547 | 3,746 |
| Zimbabwe | 5,092 | 2,646 | 5,453 | 2,292 | 4,847 | 2,912 |
| **SAPP** | **5,430** | **5,224** | **4,747** | **4,265** | **3,980** | **3,321** |

*Source: Authors.*
*Note: the HHI is calculated on the basis of annual generation output and imports grouped by type of primary energy and country where imports are sourced. In the case of SAPP overall, the HHI considers annual generation output for the regional as a whole.*

The reduction in net generation capacity from thermal generation sources can significantly contribute towards other objectives aside from reducing costs, such as a reduction in greenhouse gas emissions. Indeed, we find that full trade reduces total $CO_2$e emissions over the period 2019-2030 by 114 to 117 million tons of $CO_2$e, depending on the assumed demand scenario. This corresponds to a reduction of about 4 – 4.2% over the period 2019 to 2030 compared to a reliance on domestic generation only (**Table 15**). Trade also reinforces the trend of reduced CO2e intensity over time across all the scenarios (**Table 16**).

**Table 15 Change in total $CO_2$e emissions compared to no trade (scenario S1)**

| Total $CO_2$e emissions for the period 2019 to 2030 (mt$CO_2$e and relative to no trade) | Trade current no contribution (S2a) | Trade current contribution (S2b) | Trade current and new (S3) |
|---|---|---|---|
| **No incremental household connections** | -72 (-2.6%) | -93 (-3.3%) | -115 (-4.1%) |
| **Current rate of progress in connecting new households** | -73 (-2.6%) | -94 (-3.4%) | -117 (-4.2%) |
| **Universal access target achieved by 2030** | -66 (-2.3%) | -86 (-3.0%) | -114 (-4.0%) |

*Source: Authors' calculations using emissions factors from Energy Information Administration and International Hydropower Association (2018).*
*Note: Total $CO_2$e emissions under different trade and access scenarios is provided in* ***Annex 8****.*

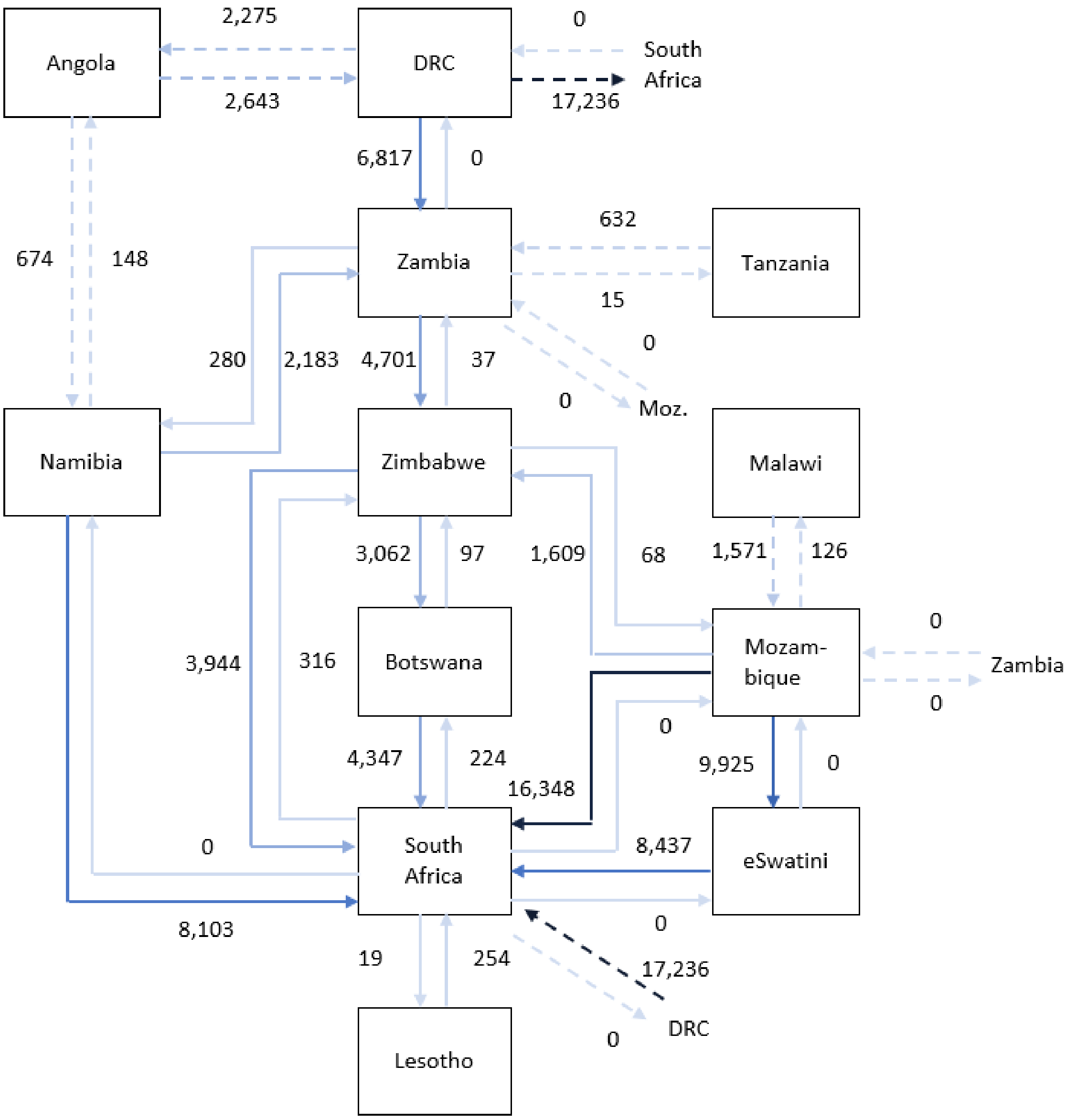
**Table 16 $CO_2e$ intensity under different trade and access scenarios**

| $CO_2e$ intensity ($gCO_2e/kWh$) | No trade (S1) | | Trade current no contribution (S2a) | | Trade current contribution (S2b) | | Trade current and new (S3) | |
|---|---|---|---|---|---|---|---|---|
| | 2019 | 2030 | 2019 | 2030 | 2019 | 2030 | 2019 | 2030 |
| **No incremental household connections** | 633 | 546 | 619 | 524 | 624 | 508 | 624 | 481 |
| **Current rate of progress in connecting new households** | 633 | 544 | 619 | 522 | 624 | 505 | 625 | 478 |
| **Universal access target achieved by 2030** | 632 | 529 | 618 | 510 | 624 | 493 | 624 | 464 |

*Source: Authors.*

The main power flows between countries allowed by trade are consistent with the changes to net capacity between the no trade and full trade scenarios. Specifically, trade allows power to flow from DRC (where more lower cost hydro generation is developed than is the case without trade), Mozambique (with lower cost gas and hydro generation) and Namibia (with lower cost gas) to the rest of the system, displacing generation elsewhere. South Africa becomes a big importer of electricity, displacing its own coal fired, gas fired and solar generation. This is consistent with Rosnes and Vennemo (2012) who find that DRC becomes a "huge exporter" of electricity under their trade scenario. The resulting electricity flows between countries are summarised for the year 2030 in **Figure 13** for the full trade and universal access target scenario.

**Figure 13: Electricity flows in 2030 with full trade and universal access target (GWh)**




*Source: Authors.*

*Note: Interconnectors depicted by solid lines are existing interconnectors and those depicted by dashed lines are possible new interconnectors, not all of which are built under the full trade scenario. Shading is used to depict the annual flow quantity with the darkest shading used for the greatest annual flow. The interconnector from DRC to South Africa is an HVDC project that could potentially have invertor stations along the route from Inga to South Africa, e.g. in Zambia. While in this chart we show all of the possible country pairs currently considered for development in the SAPP region, a number of these are not developed according to the least-cost optimisation model. This is represented by a zero flow in both directions of the interconnector. We note that for some interconnectors, only unidirectional flow takes place, which is represented by a zero flow in one direction of the interconnector.*

To provide an intuitive feel for our findings, we also look at the forward looking levelized wholesale cost of providing incremental access over the period from 2019 to 2030 for each of the four trade scenarios. This is calculated as the change in the present value cost divided by the change in the present value generation volume, where the change is with respect to the status quo access scenario. As shown in **Table 17**, the levelised wholesale cost of serving new customers tends to fall with trade and increase with a more stringent access target. With no trade and the current rate of progress, the levelised cost of supplying incremental household customers is US$2019 57.32 per MWh, falling to US$2019 55.62 per MWh with full trade.[58] With a target of universal access being met in 2030, the levelised cost of providing incremental access is US$2019 61.38 per MWh with no trade, falling to US$2019 58.85 per MWh with full trade. This implies that as the change in demand grows, the importance of trade tends to increase, suggesting that countries with an ambition to achieve universal access by 2030 should consider trade as a way to reduce the incremental costs of proving access. However, we note that the levelised cost is sensitive to the specific situation of the power sector as seen, for example, by the higher levelised cost for providing access when using current interconnectors for trade but with no contribution from interconnectors to the capacity requirement (S2a).

**Table 17 Levelised wholesale cost under different trade and access scenarios**

| (US$2019 per MWh) | No trade (S1) | Trade current no contribution (S2a) | Trade current contribution (S2b) | Trade current and new (S3) |
|---|---|---|---|---|
| No incremental household connections | n/a | n/a | n/a | n/a |
| Current rate of progress in connecting new households | 57.32 | 57.39 | 56.11 | 55.62 |
| Universal access target achieved by 2030 | 61.38 | 63.17 | 61.04 | 58.85 |

*Source: Authors.*
*Note: The levelised wholesale cost includes the levelised cost of generation and new interconnectors.*

We note that trade reduces the cost not only of providing incremental access but also the costs of serving all customers on the power system. Therefore, while trade is a vital tool for reducing the cost of access, the benefits of trade to the power system are much wider than solely the cost of supplying incremental connections. This is an extremely important result for policy makers to take note of because it means that, relative to the costs of connecting new customers, the benefits from trade are large. The region is currently close to the top left corner of **Table 12** and, by moving to universal access while at the same time optimizing trade (i.e. moving to the bottom right corner), the region actually reduces costs.

Although at first glance surprising, this result stems from the bulk of the forward-looking costs of the power sector relating to meeting the demand of existing customers and their demand growth, and only a relatively small fraction of costs relating to connecting and serving new households. Rosnes and Vennemo (2012) find a similar

[58] Here MWh refers to energy injected onto the transmission network and not to energy taken from the network by end consumers, with the difference being technical losses.

result, in that "*the main cost of providing electricity to Africa does not depend on providing electricity access to new customers. The main cost depends on meeting the market demand associated with the economic growth*". Indeed, our analysis shows that while the incremental demand from new residential on-grid connections increases the on the grid sent-out demand by just over 6% under the universal access target by 2030, the forward-looking wholesale costs increases by little over 4% over the forecast horizon. Since households are connected progressively over time, only about half of the incremental consumption is on the system on average throughout the forecast horizon. We note, however, that even doubling the consumption of those newly connected would not change our conclusion of a relatively small fraction of forward-looking wholesale costs relating to incremental residential demand of those that currently lack access to electricity.

We reiterate the point that our analysis focuses on the forward-looking cost of generation investment and operating cost and new interconnector investments, which does not take account of the effects of trade on other transmission and distribution costs, including the costs of last mile connections. However, we note that holding demand constant and changing the ability to trade is unlikely to significantly affect distribution costs. On the other hand, other transmission costs (i.e. other than interconnector investment costs) could increase or decrease as a result of additional trade – some other transmission costs may be avoided due to the need to connect fewer power stations or other transmission costs may increase to accommodate cross border flows. Therefore, it is not clear that the change in total system costs would be systematically higher or lower than our estimate of the absolute change to generation and interconnector investment costs as a result of regional trade. What is clear, however, is that to understand the total incremental cost of connecting new customers and supplying them, one would need to take into account the effect of incremental access on distribution costs, including the cost of last mile connections.

*Sensitivity analysis*

We also applied three sensitivities to the model to better understand drivers of the benefits of trade and the robustness of our results, as follows:

- *No Grand Inga*. Various projects to develop up to 40,000 MW of hydro generation in DRC on the Congo River at Inga Falls have been proposed. These projects can be developed in stages and we include 16,454 MW of candidate hydro projects at the falls, much of whose output would be exported. However, the coordination required among several countries to develop these projects and the associated transmission lines required to deliver the power to customers will make their development complex. Recognising this complexity and the potential importance of the Grand Inga projects as drivers of the benefits from trade in the SAPP region, in this sensitivity these hydro projects are not available as candidate plants. Other smaller candidate hydro projects in DRC continue to be available for development.

- *Drought*. We model hydro power stations as producing their expected output in each year. However, we discuss the importance of using trade to help mitigate the effects of drought and therefore it is interesting to understand the effects of a drought on the benefits of trade. While a localised drought may increase the benefits of trade, a more widespread drought could potentially reduce the benefits of trade, making it difficult to generalise from the results for a specific modelled drought to all droughts. Nevertheless, in this sensitivity we assume that a drought in the Zambezi River basin reduces output of hydro power stations on the Zambezi and Kafue rivers to two thirds of expected annual output in three years, 2019, 2028 and 2029. This applies both to existing and candidate hydro plants on these rivers.
- *Discount rate*. We use a 6% real discount rate in the analysis, representing the social discount rate in the SAPP region, in line with the discount rate used in the SAPP Pool Plan (2017). However, some countries may have a different discount rate, discount rates may change over time and developers may use a higher discount rate to reflect their average cost of capital. The choice of discount rate is important because it helps determine the optimal type of generation developed to meet demand, with a low discount rate favouring projects with higher up-front capital costs, e.g. hydro and solar PV, and a high discount rate favouring projects with lower up-front costs such as gas fired power plants. As the type of power plants developed changes, the benefits from trade may change and, therefore, we explore the sensitivity of results to applying a higher discount rate of 10%.

**Table 18** shows the proportional reduction in costs due to trade for the base case and each of the three sensitivities. Without Grand Inga, trade reduces present value forward looking wholesale costs by between 5 and 5.2% compared to a scenario with no trade. Similarly, with droughts the reduction in costs due to trade is smaller than for the base case, at between 4.9 and 5.1%. Conversely, the relative benefit of trade increases with a higher discount rate to between 6.4 and 6.5% of wholesale costs without trade.

**Table 18 Proportional savings in forward-looking wholesale costs - sensitivities**

| | Trade current and new (S3) – base case | Trade current and new (S3) – No Grand Inga | Trade current and new (S3) – Drought | Trade current and new (S3) – 10% discount rate |
|---|---|---|---|---|
| **No incremental household connections** | 5.8% | 5.2% | 5.1% | 6.5% |
| **Universal access target achieved by 2030** | 5.7% | 5.0% | 4.9% | 6.4% |

*Source: Authors*

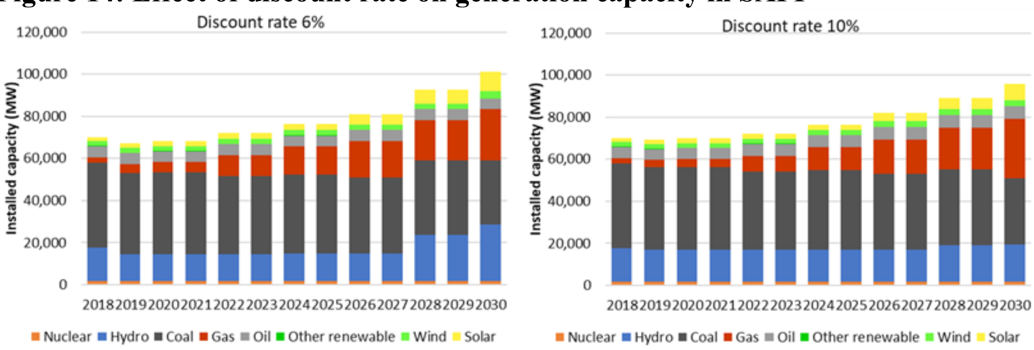
Without Grand Inga as a candidate project DRC builds less capacity towards the end of the forecast period, exporting less power. In turn, we find that South Africa builds more generation capacity, in particular more coal and gas fired generation, and relies less on imports from the region. Although the effect on the benefits of trade from Grand Inga not being developed is relatively small, this is partly because the reduction in trade flows happens towards the end of the period. Total export flows in the SAPP region fall by 15% in 2025 compared to the base case scenario, as the region anticipates that Grand Inga will not be developed, and by 46% in 2030. We note that with a longer period of analysis, the effects of not developing Grand Inga on the benefits of trade to the region may be more pronounced.

With the droughts, in 2019 export flows from Zambia and Mozambique fall and although these are partially offset by greater exports from South Africa, the overall effect of the drought is to reduce export flows in the SAPP region to 83 percent of flows compared to the base case (i.e. without the drought in the Zambezi / Kafue river basins). Noting that our modelling framework provides all decision makers with perfect foresight over the planning horizon, South Africa anticipates the drought in 2028/29 and builds more hydro, solar and gas fired generation than without the drought. This means that South Africa reduces its reliance on imports not only during the 2028/29 drought period but also in prior years with this sensitivity. During the drought of 2028/29 export flows are 38% below flows without the drought.

The results of the drought sensitivity point to an issue with modelling uncertainty with an optimisation model that has perfect foresight. A drought is an unexpected event and yet in this sensitivity the central planners at the heart of our model anticipate the drought in 2028/29 at 0:00 hours on 1st January 2019 when they first begin to think about how best to develop and operate the regional power system until 2030, and plan accordingly. Due to this anomaly and the difficulty in modelling a "representative" drought, we take the view that it is not possible to draw generalised conclusions from the drought sensitivity. Rather, one can only draw tentative conclusions about the effects of this particular drought, i.e. that exports from Zambia and Mozambique fall while South Africa's reliance on imports declines.

With a higher discount rate, less hydro, solar PV and wind generation is developed than with the social discount rate of 6%, and more gas, coal and oil fired generation is developed, in line with our expectations. This is because those power plants with relatively high up front capital expenditure and relatively low ongoing operating costs become less competitive with the higher discount rate then power plants with lower up front capital costs and higher ongoing operating costs. The switch away from renewable generation means that overall less capacity is developed in the SAPP region with the higher discount rate. These results are summarised in **Figure 14**.

**Figure 14: Effect of discount rate on generation capacity in SAPP**




*Source: Authors.*
*Note: Universal access target achieved by 2030, trade current and new (S3).*

We note that although the relative benefits of trade are greater with the higher discount rate, trade volumes are significantly lower, with total export flows in 2030 amounting to 49,620 GWh or about 50% of total export flows with a 6% discount rate (96,090 GWh). This apparent anomaly is because with the higher discount rate, trade avoids a greater amount of generation investment in early years, and discounting places a lower weight on cost reductions due to the high trade flows in later years. Importantly, Grand Inga is not developed with the higher discount rate, and therefore DRC moves from being a major exporter with the lower discount rate to having almost balanced import and export flows in 2030 with the 10% discount rate. Conversely, with the higher discount rate South Africa's imports in 2030 are estimated to be about 55% lower than under the base-case scenario, with SA relying more heavily on coal and gas fired generation to meet demand. The higher discount rate deters some transmission investment, with neither Angola nor Malawi being interconnected to the rest of the SAPP region. As with the no Grand Inga sensitivity, the effects of the higher discount rate on the benefits of trade to the region may be more pronounced with a longer period of analysis.

# 4.5. Conclusions

The aim of this study was to inform readers and policy makers of the importance of regional integration of power markets in reducing the wholesale cost of electricity supply, which in turn has the potential to reduce the often-cited affordability barrier to electrification in SSA. Today, less than half of the population in SSA has access to electricity, and even those with access are often faced with unreliable supply as a result of power sectors operating with insufficient generation capacity and a lack of financial resources. Reducing system costs is therefore imperative not only for meeting the policy objectives of universal electricity access by 2030 as stipulated in the SDG 7 but also as a means to enhancing the reliability and sustainability of the power sectors overall in SSA.

While the general conclusions reached in this study are likely to be relevant for the whole of SSA, we focussed our analysis on the countries grouped under the Southern African Power Pool (SAPP). To quantify the economic benefits of regionally optimised cross-border electricity trade we relied on the regional power system optimisation model with endogenous decisions about cross border interconnection investments in the SAPP region. Using this model we estimate the forward looking wholesale costs of supply under different scenarios for interconnection in the region and demand over the period 2019-2030, whose end coincides with the policy target for achieving universal access to electricity.

Our analysis shows that trade using existing interconnectors has the potential to reduce the forward-looking cost of generation by over 8 US$2019 billion over the period 2019-2030, which is a little over 5% of costs without trade. The incremental benefit of building new interconnectors for trade is relatively small by comparison, reducing costs by less than a further 1 percentage point. Comparing modelled trade flows to reported trade flows for 2018 suggests that the SAPP region is not utilising existing interconnector capacity efficiently and that there are likely to be additional opportunities for efficient trade using existing infrastructure. This gives rise to two important policy implications:

- Firstly, countries in the SAPP region should focus on developing what is referred to as the soft infrastructure required to facilitate trade using existing interconnectors in order to increase the economic benefits from trade. This soft infrastructure relates to developing a broad range of mechanisms and processes including setting transmission charges so as to encourage efficient trade, further developing trading platforms, building trust in neighbouring countries, integrating regional resources into domestic generation planning, and recognising the security benefits of import capacity, among others.
- Secondly, unless interconnector capacity is efficiently used, it is quite possible that economic studies used to justify the development of new interconnector capacity will tend to overstate the economic benefits of those projects. If the reality is that new interconnectors will be under-utilised, it is important that this is recognised when analysing the costs and benefits of the new projects. If not, somewhat perversely, too much new interconnector capacity could be built, at least until such time as the "soft infrastructure" catches up to allow more economic trade.

Neither implication suggests that no new interconnectors should be built. Indeed, we would encourage that new interconnectors are built when economically efficient to do so, since trade can be a powerful tool for reducing the cost of providing access. Our analysis shows that the incremental costs of providing access are lowest when electricity is traded efficiently between countries and new interconnectors are built when economic to do so. We find that with no trade and the current rate of progress towards providing access, the levelised cost of providing additional access is US$2019 57.32 per MWh, falling to US$2019 55.62 per MWh with full trade. With a target of universal access being met in 2030, the levelised cost of providing additional access is US$2019 61.38 per MWh with no trade, falling to US$2019 58.85 per MWh with full trade. This suggests that as the change in demand grows, the importance of trade increases. The implication is that as countries strive more strongly to achieve universal access by the SDG 7 target year (2030), trade will become increasingly important as a way to constrain costs.

Irrespective as to the small reduction in the levelised costs due to trade, electricity trade has the effect of decreasing the overall system costs and hence, can play a vital role in overcoming the challenges of low electricity access but also the challenges of providing reliable supply to incremental and existing customers while also reducing the amount of unserved demand. Indeed, we find that by increasing trade it may actually be possible to reduce wholesale costs while also providing universal access. This suggests a clear policy implication of the need to consider possibilities for trade when developing national power system development plans and electrification strategies.

Our analysis shows that increased trade would not only bring economic benefits but also environmental benefits. Over the whole SAPP region, by 2030 we estimate that 3,330 MW less generation capacity would need to be built with full trade than without trade, while meeting the same level of demand and security of supply requirements. Most of the reduction in net generation capacity is related to avoided coal fired generation capacity (7,330 MW by 2030), particularly in South Africa and Zimbabwe, and avoided oil fired generation capacity (1,950 MW by 2030). In other words, unrestricted electricity trade using existing transmission infrastructure in the region is estimated to save 86-93 million tons of $CO_2$e over the period 2019 – 2030 and an additional 22-30 million tons of $CO_2$e with economic development of new interconnector capacity in the region.

Finally, it would be interesting to apply the model developed as part of this analysis to consider the costs and benefits of trade for each country and for different stakeholders (consumers, producers) in each country so as to help understand possible barriers to trade and to consider how those barriers might be addressed. One approach to analysing the costs and benefits for each country would involve using our modelling framework and assigning a value to electricity traded between countries (where the value could lie anywhere between the system marginal cost of the exporting country and the system marginal cost of the importing country) and allocating the cost of new interconnectors between the importing and exporting countries.[59] Indeed, this type of question has been addressed elsewhere, e.g. the European Union has developed a mechanism to re-allocate costs of regional infrastructure projects among countries so as to reduce barriers to developing projects that are economically beneficial (European Union, 2013).

Another interesting extension to the study would be to include spinning reserve dispatch constraints in the model. The importance of spinning reserves will increase over time as VRE generation penetration increases. However, hydro generation and battery storage could be used to provide spinning reserve and interconnectors could be used to allow spinning reserves in one region to respond to a system event in another region. Therefore, including spinning reserve dispatch constraints may increase the value of interconnectors.

[59] The value of interconnector import capacity in meeting the capacity requirement in a country could also be allocated between importing and exporting countries.

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# Chapter 5

# General conclusions

A well-developed financial system, including access to financial services, and access to reliable sources of energy, are important means to a development end. A growing body of research shows their importance for ensuring inclusive and sustainable economic growth, poverty eradication and their role in the achievement of other SDGs (Stein, 2013; Demirgüç-Kunt et al., 2018; IEA, 2010; UN, 2017; UN, 2018; Sarkodie and Adams, 2020).

Yet, the development of the financial and power sectors and access to these basic services remains limited in most countries in Sub-Saharan Africa (SSA). Furthermore, there are important linkages between development aspects in the two sectors. Financial developments, such as new means of payments (mobile account, mobile payments), have helped increase access to modern energy services, enabling solar companies to enter the market with pay-as-you-go energy services, giving millions of low-income households access to electricity for the first time in their lives. Conversely, paying for energy services on a regular basis helps households and businesses establish a credit rating, facilitating access to formal banking services and asset ownership (UN, 2018b). Without adequate financing a better energy solution for households trapped in energy poverty is, however, often unreachable.

With this context in mind, my research aimed to broaden understanding of the role of financial development in facilitating economic growth (Chapter 2), gain a better understanding of the challenges ahead of meeting the universal electricity access target

(Chapter 3), and of ways to decrease the economic costs of electricity access through regional trade (Chapter 4). The ultimate objective being to enhance research and to guide policy decisions in this area in view of the need to accelerate progress towards achieving the 2030 Agenda for Sustainable Development.

In an attempt to shed more light on the conflicting findings on the link between financial development and economic growth, I analysed 1334 estimates from 67 studies that examine the relationship between financial development and economic growth using meta-analysis techniques. My results suggest that the published empirical studies identify an authentic positive link between financial development and economic growth, but the individual estimates vary widely. I find that the estimates of the effect reported in the literature are not overwhelmingly driven by so-called publication selection bias, i.e., the preference of researchers, referees, or editors for positive and significant estimates. The results also indicate that the differences in the reported estimates arise not only from the research design (for example, from addressing or ignoring endogeneity), but also from real heterogeneity in the effect.

Most importantly, supported by results of the multivariate meta-regression, I find that the effect of financial development on growth varies across regions and time periods. This finding has an important implication for future research as it is apparent that it is not sensible to pool different regions together since the estimated effects are not stable across regions. The results suggest that the role of financial development declined in the 1990s compared to the 1980s (consistent with Roussuau and Wachtel, 2011) and the effect seems to be smaller in less developed countries (SSA, South Asia) and higher in richer countries (Europe). This suggests a pattern where a certain level of financial and economic development increases the growth effect of financial development, supporting the view that the role of financial development may also vary over time.

My results also suggest that the structure of a country's financial system is important for the pace of economic growth, as suggested, for example, by Demirgüç-Kunt and Levine (1996). That is, I find that stock market-oriented financial systems tend to be more conducive to growth than bank-oriented financial systems, which is in line with the theoretical model of Fecht et al. (2008), as well as empirical evidence by Luintel et al. (2008) and Chu (2020), among others.

While my analysis shows that the role of financial development is generally weaker in less developed countries, it is possible that this is because of the limited access to financial services in those countries. Furthermore, meta-analysis techniques rely on already published research examining the role of financial development in economic growth. These studies have, however, predominantly focussed on the role of financial intermediaries and stock markets with researchers relying on indicators such as financial depth and financial activity as proxies for the level of financial development. This means that there was a very limited focus on how financial services are provided in poorer countries, the role of mobile financial services or the role of microfinance institutions, all of which have been gaining in importance in SSA (Demirgüç-Kunt et al., 2018). The primary studies similarly did not consider measures of financial inclusion, and the availability of data for less developed countries among the primary studies was limited. Therefore, more research is needed to derive relevant policy implications suited specifically to developing countries, with results of this meta-analysis providing guidance on how to conduct policy-relevant empirical research in this area.

Including new ways of how financial services are provided in poorer countries as well as the importance of financial inclusion for development would be a natural extension of the current research. This goes back to the difficulty in measuring the development of a financial system discussed in this thesis. Other measures that could be used as proxies for financial development in primary studies include measures of financial efficiency, access to finance and financial stability, in line with data contained in the new Global Financial Development Database (Cihak et al., 2013; GFDD, 2019). Another natural extension of the research contained in this thesis would also be to incorporate more recent advances in the field of meta-analysis, including Bayesian model averaging.

With respect to extending access to electricity, the prospects of meeting SDG 7 look challenging in many countries in SSA, despite access being vital for sustainable development and a necessary condition for eradicating poverty and embarking on a path of inclusive economic growth (IEA, 2010; SE4ALL, 2017; UN, 2017; Sarkodie and Adams, 2020). My research shows that the recent progress in providing access across many countries in SSA is insufficient to meet the 2030 Agenda for Sustainable Development endorsed by all United Nations member states. Indeed, a significant step up in effort is required if the objective of universal access by 2030 is to be met. Specifically, if the current rate of progress continues SSA would fail to meet SDG 7 by a large margin and around 600 million people would still rely on more polluting and inadequate alternatives to electricity in 2030 (over 40% of SSA's population).

With uneven progress in the recent past, a number of countries in SSA are likely to struggle to achieve the 2030 target without increased effort. The situation is even more concerning among countries in SAPP, where only 45% of the population would have access to electricity by 2030 under the current rate of progress and even less if South Africa as a regional outlier is excluded. In fact, the current rate of progress would need to increase by a factor of 4.5 if universal access to electricity were to be achieved by 2030 in the SAPP region. With the need to scale up progress in extending access to modern energy solutions, my research was aimed at informing decision-makers and other stakeholders as to the true costs of providing access to electricity in SSA. To do so, we developed a detailed least cost optimisation model to assess the incremental generation costs of providing on-grid access to electricity to currently unelectrified households.

Despite the significant level of effort required, my analysis shows that when considering only the incremental costs of achieving universal access rather than looking at the overall costs of power sector expansion to serve the overall incremental load (i.e. growing demand of existing customers), the forward-looking generation costs of achieving universal access is relatively small compared to the overall generation costs. That is, assuming that approximately 60% of those newly gaining access would do so through the main grid, the total forward-looking on-grid generation costs are forecast to increase by only 3.6 to 7.8% for the period 2018 to 2030 in the SAPP region. In other words, providing modern electricity solutions to these newly connected households currently deprived of electricity and those that would need to be newly connected to take into account future population growth in the SAPP region, would increase the present value forward-looking on-grid generation costs by between 5.2 and 11.4 billion US$2018 over the period 2018 to 2030, depending on the consumption level of newly connected households. This is relatively low compared to the overall forward-looking system generation cost of serving the current households and the non-residential sectors of the economy, estimated at 146 US$2018 billion in the SAPP region between 2018 and 2030.

The incremental costs of universal access correspond to a levelised generation cost of between 65 to 70 US$2018 per MWh consumed by the newly connected households under universal access. This corresponds to between 108 and 116 US$2018 per MWh for the overall costs of electricity supply at the point of consumption, assuming that generation costs represent about 60% of the overall cost of supply. Therefore, while the level of effort required to connect new households is considerable, the incremental costs of making that additional effort is relatively low, suggesting that policymakers should strive to increase access to electricity. In fact, the levelised cost of providing access is lower than what a typical household pays for poor alternatives to electricity, such as kerosene for lighting (Schnitzer et al., 2014), especially when measured based on the cost per lumen hours (Bhatia and Angelou, 2015).

The relatively low incremental costs of serving the newly connected households can be explained by not only the relatively low level of incremental demand of newly connected households (which is consistent with meeting their basic needs), but also by the fact that the analysis dynamically optimises the use of electricity interconnection capacity between countries, further decreasing the costs of electricity supply.[60] This suggests an urgent need for policymakers of countries not on target to achieve universal access by the SDG 7 target year to accelerate the rate at which electricity access is provided, and for the access target to be taken into account in national and regional electricity planning.

Motivated by the results of Chapter 3 and in view of the fact that the lack of access to modern electricity services is often linked to affordability issues, which arise in both the supply and demand for electricity access, I explored in Chapter 4 how to reduce the underlying cost of supply. Several studies have focussed on the benefits of regional integration on reducing the costs of supply and improving security of supply (e.g. Bowen et al., 1999; Graeber et al., 2005; Gnansounou et al., 2007; Timilsina and Toman, 2016). However, to the best of my knowledge there was no recent study in the context of SSA that assessed the potential for regional integration not only to reduce the costs of supply but also to contribute to meeting the objective of universal access to electricity.

I show that regional integration plays an important role in reducing the costs of electricity supply, and hence can play a vital role in overcoming the challenges of low electricity access in SSA. Specifically, utilising the existing interconnection capacity efficiently has the potential to reduce the forward-looking cost of generation by over 8 US$2019 billion over the period 2019-2030, which is a little over 5% of costs without trade. The incremental benefit of building new interconnectors for trade is relatively small by comparison, reducing costs by less than a further 1 percentage point.

The analysis shows that the incremental costs of providing access are lowest when electricity is traded efficiently between countries and new interconnectors are built when economic to do so. We find that with no trade and the current rate of progress towards

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[60] I note that the remaining 40% would gain access through off grid solutions (mini grids and standalone solutions) which would add to the overall costs of providing universal access in the region.

providing access, the levelised cost of providing additional access is US$2019 57.32 per MWh, falling to US$2019 55.62 per MWh with full trade. With a target of universal access being met in 2030, the levelised cost of providing additional access is US$2019 61.38 per MWh with no trade, falling to US$2019 58.85 per MWh with full trade. This suggests that as the change in demand grows, the importance of trade increases. The implication is that as countries strive more strongly to achieve universal access by the SDG 7 target year (2030), trade will become increasingly important as a way to constrain costs.

While not the primary focus of this thesis, the analysis also shows that increased trade would not only bring economic benefits but also environmental benefits. Over the whole SAPP region, by 2030 we estimate that 3,330 MW less generation capacity would need to be built with full trade than without trade, while meeting the same level of demand and security of supply requirements. Most of the reduction in net generation capacity is related to avoided coal fired generation capacity (7,330 MW by 2030), particularly in South Africa and Zimbabwe, and avoided oil fired generation capacity (1,950 MW by 2030). In other words, unrestricted electricity trade using existing transmission infrastructure in the region is estimated to save 86-93 million tons of $CO_2e$ over the period 2019 – 2030 and an additional 22-30 million tons of $CO_2e$ with economic development of new interconnector capacity in the region.

Given the benefits of trade, for a country naturally endowed with energy resources but low access rates (for example, DRC), receipts from exports could potentially contribute towards financing investments needed for domestic access, lowering the affordability constraint related to electricity access, and hence help to promote the achievement of other SDGs. This could also be an area for future research since it would be interesting to apply the model developed as part of this analysis to consider the costs and benefits of trade for each country and for different stakeholders (consumers, producers) in each country so as to help understand possible barriers to trade and then to consider how those barriers might be addressed. Indeed, this question has been addressed elsewhere, e.g. the European Union has developed a mechanism to re-allocate costs of regional infrastructure projects among countries so as to reduce barriers to developing projects that are economically beneficial (European Union, 2013).

Another interesting extension to the research in this thesis would be to include spinning reserve dispatch constraints in the model. The importance of spinning reserves will increase over time as VRE generation penetration increases. However, hydro generation and battery storage could be used to provide spinning reserve and interconnectors could be used to allow spinning reserves in one region to respond to a system event in another region. Therefore, including spinning reserve dispatch constraints may increase the value of interconnectors.

Finally, although my focus was on a group of countries in SSA, I note that the framework for analysis and the conclusions reached are likely to be applicable to other countries and regions within SSA and to regions elsewhere with poor access to electricity.

# Annex 1: Studies used in the Meta-Analysis

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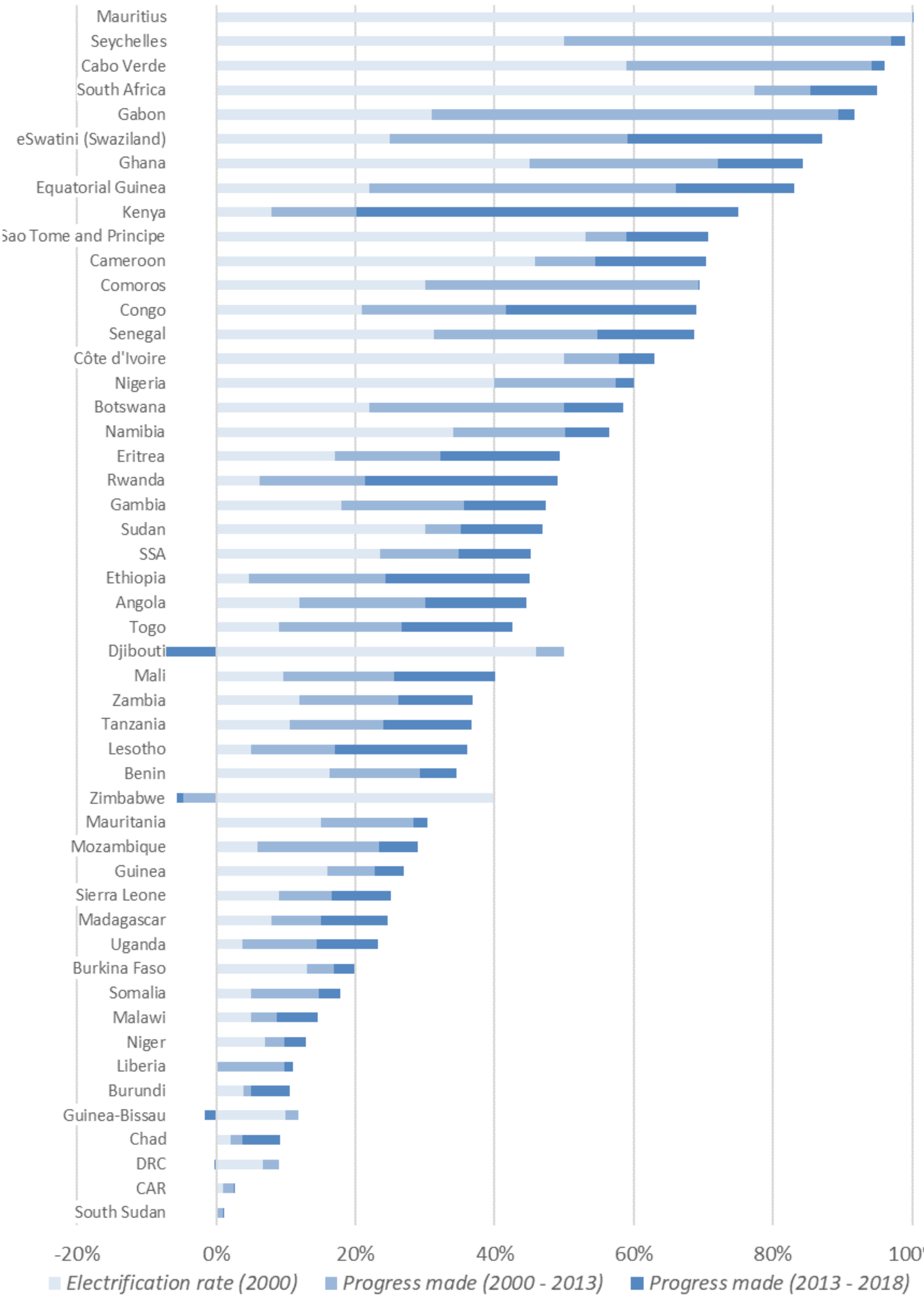
# Annex 2: Electricity access in SSA and its outlook

**Figure 15: Current electricity access rates and recent progress (2018)**




*Source: Authors' compilation and calculation based on IEA (2019a), IEA (2018), IEA (2017) and IEA (2015).*
*Note: Where IEA reports an obvious outlier in their annual electricity access data for a country, we take the average of the access rates of the two adjacent years for that country for which electricity access data were available. This was for example the case for Botswana, where IEA (2015) reports national electrification rate of 66% for the year 2013, while IEA (2019a) reports an electricity access rate of 45% and 53% for the year 2010 and 2015, respectively. Therefore, we assume a 50% access rate for the year 2013 instead of the 66% access rate as reported by IEA (2015).*

**Table 19: Outlook for electricity access with the current rate of progress**

| Country | Power pool | Population (million) | GDP p.c. (current US$) | Electrification rate (2013) | Electrification rate (2018) | Achieved access rate (2030) |
|---|---|---|---|---|---|---|
| Mauritius | Island state | 1.3 | 11,239 | 100% | 100% | 100% |
| Seychelles | Island state | 0.1 | 16,434 | 97% | 99% | 100% |
| Cabo Verde | Island state | 0.5 | 3,654 | 94% | 96% | 100% |
| South Africa | SAPP | 57.8 | 6,374 | 85% | 95% | 100% |
| Gabon | CAPP | 2.1 | 8,030 | 89% | 92% | 100% |
| eSwatini (Swaziland) | SAPP | 1.1 | 4,140 | 59% | 87% | 100% |
| Ghana | WAPP | 29.8 | 2,202 | 72% | 84% | 100% |
| Equatorial Guinea | CAPP | 1.3 | 4,061 | 66% | 83% | 100% |
| Kenya | EAPP | 51.4 | 1,711 | 20% | 75% | 100% |
| Sao Tome and Principe | CAPP<br>Island state | 0.2 | 2,001 | 59% | 71% | 88% |
| Cameroon | CAPP | 25.2 | 1,527 | 55% | 70% | 93% |
| Comoros | Island state | 0.8 | 1,445 | 69% | 70% | 69% |
| Congo | CAPP | 5.2 | 2,148 | 42% | 69% | 100% |
| Senegal | WAPP | 15.9 | 1,522 | 55% | 69% | 88% |
| Côte d'Ivoire | WAPP | 25.1 | 1,716 | 58% | 63% | 68% |
| Nigeria | WAPP | 195.9 | 2,028 | 57% | 60% | 62% |
| Botswana | SAPP | 2.3 | 8,259 | 50% | 59% | 72% |
| Namibia | SAPP | 2.4 | 5,931 | 50% | 56% | 67% |
| Eritrea | | 3.9 | 2,144 | 32% | 49% | 73% |
| Rwanda | EAPP | 12.3 | 773 | 21% | 49% | 92% |
| Gambia | WAPP | 2.3 | 712 | 36% | 47% | 63% |
| Sudan | EAPP | 41.8 | 1,147 | 35% | 47% | 64% |
| Ethiopia | EAPP | 109.2 | 772 | 24% | 45% | 77% |
| Angola | CAPP, SAPP | 30.8 | 3,432 | 30% | 45% | 62% |
| Togo | WAPP | 7.9 | 672 | 27% | 43% | 67% |
| Djibouti | EAPP | 1.0 | 2,050 | 50% | 42% | 36% |
| Mali | WAPP | 19.1 | 901 | 26% | 40% | 59% |
| Zambia | SAPP | 17.4 | 1,540 | 26% | 37% | 51% |
| Tanzania | SAPP, EAPP | 56.3 | 1,051 | 24% | 37% | 53% |
| Lesotho | SAPP | 2.1 | 1,324 | 17% | 36% | 76% |
| Benin | WAPP | 11.5 | 902 | 29% | 35% | 41% |
| Zimbabwe | SAPP | 14.4 | 2,147 | 35% | 34% | 31% |
| Mauritania | | 4.4 | 1,219 | 28% | 30% | 33% |
| Mozambique | SAPP | 29.5 | 490 | 23% | 29% | 36% |
| Guinea | WAPP | 12.4 | 885 | 23% | 27% | 32% |
| Sierra Leone | WAPP | 7.7 | 523 | 17% | 25% | 39% |
| Madagascar | Island state | 26.3 | 461 | 15% | 25% | 39% |
| Uganda | EAPP | 42.7 | 643 | 15% | 23% | 36% |
| Burkina Faso | WAPP | 19.8 | 731 | 17% | 20% | 23% |
| Somalia | | 15.0 | 315 | 15% | 18% | 21% |
| Malawi | SAPP | 18.1 | 389 | 9% | 15% | 23% |
| Niger | WAPP | 22.4 | 412 | 10% | 13% | 16% |
| Liberia | WAPP | 4.8 | 674 | 10% | 11% | 13% |
| Burundi | EAPP, CAPP | 11.2 | 275 | 5% | 11% | 18% |
| Guinea-Bissau | WAPP | 1.9 | 778 | 12% | 10% | 8% |
| Chad | CAPP | 15.5 | 730 | 4% | 9% | 17% |
| DRC | SAPP<br>EAPP<br>CAPP | 84.1 | 562 | 9% | 9% | 8% |
| Central African Republic | CAPP | 4.7 | 510 | 3% | 3% | 3% |
| South Sudan | | 11.0 | 270 | 1% | 1% | 1% |
| **Sub-Saharan Africa** | | **1,080** | **1,583** | **35%** | **45%** | **56%** |
| **Total, excluding SA** | | **1,022** | **1,312** | **32%** | **42%** | **54%** |

*Source: Authors based on IEA (2019a), IEA (2018), IEA (2017), IEA (2015) and WDI (2019).*

# Annex 3: Power system expansion model

The objective function of the power system expansion model is to minimise the forward looking fixed and variable costs over the forecast horizon, as follows:

$$Minimise\ cost = \sum_{t=1}^{T} \frac{(\sum_{i=1}^{I} G_{it}FC_{it} + \sum_{i=1}^{I} QP_{it}VC_{it})}{(1+r)^t} \qquad (1)$$

where:[61,62]

- *G* is the installed capacity (MW) of power plant *i* in period *t*;
- *FC* is the annuitized fixed costs per MW of power plant *i* in period *t*, which for an existing power plant represents only the annual fixed O&M costs whereas for a newly constructed power plant represents the annual fixed O&M cost and the annuitized capital cost;
- *QP* is the electricity production (MWh) from power plant *i* in period *t*;
- *VC* is the variable costs per MWh of power plant *i* in period *t*;
- *r* is the real discount rate used to express all costs as the present value at a common point in time.

The model's decision variables are the amount of generation capacity built in a year, the capacity (if any) of each power station to close in a year, the amount of capacity shortfall in a year, the amount of electricity production in an hour from each power station (existing or newly built), the amount of load not served in each hour, and the quantity of electricity flows on transmission lines between countries in an hour. Further in Chapter 4, we added endogenous decisions about the amount of interconnector capacity to be developed in the region, which we further discuss in **Annex 5** when we look at current and possible future interconnector transfer capacities in the region.

Like the real world, it may be economically efficient to develop the power system such that it is unable to meet peak demand in all hours, resulting in some load being unserved. The model is free to choose load not served over investing in and operating generation if this is the least cost approach compared to meeting demand at any cost. To model this, load not served is given a penalty, a cost of $1,000 per MWh, in line with the

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[61] For simplicity, here we show time using a single subscript, *t*. Generation variable operating costs (fuel costs and variable operations and maintenance costs) are applied to generation output on an hourly basis whereas the annuitized fixed costs of generation investment and the annual fixed cost of generation operations and maintenance are applied to installed capacity on an annual basis.

[62] Investment costs are represented as an annuity, using the technical life of the power plant. The annuity cannot be avoided by subsequently closing a newly constructed power plant.

cost of unserved energy in SAPP Pool Plan (2017) to incentivise the model to serve demand. Additional constraints are applied to the decision variables such as:

- for each region and each hour, demand must equal generation plus load not served plus imports less exports;
- for each power plant and each hour, production from the power plant must be no greater than the available capacity of the power plant; and
- for each transmission line and each hour, power flows on the transmission line must be no greater than the capacity of the line.

For example, the demand-supply constraint in each country in each period *t* (i.e. for each hour) is defined as follows:

$$\sum_{i=1}^{I}(QP_{iy} - QC_{iy}) + LoL_y + \sum_{y'=1}^{Y'}(IMP_{y'} - LL_{ny'}) - \sum_{y'=1}^{Y'} EXP_{y'} = D_y, \forall y, \forall y', \forall t, y \neq y' \qquad (2)$$

Subject to the following constraints for each country *y*:

$$QP_i / H_t \leq GA_i \forall\ i, \forall\ t$$

$$IMP_{y,y'} / H_t \leq IC_{y,y'} \forall\ y, \forall\ t$$

$$\exp_{y',y} / H_t \leq IC_{y',y} \forall\ y, \forall\ t$$

Where:

- *QP* is the electricity production (MWh) from power plant *i* in country *y* in period *t*;
- *QC* is the own consumption (MWh) of power plant *i* in country *y* in period *t*;
- *LoL* is the load not served (MWh) in country *y* in period *t*;
- *IMP* is the flow (MWh) from all other countries *y'* to country *y* in time *t*;
- *EXP* is the flow (MWh) from country *y* to country *y'* in time *t*;
- *D* is the gross demand (MWh) in country *y* in period *t*;
- *H* is the duration (hours) of period *t (H=1)*;
- *GA* is the available generation capacity (MW) of power plant *i* in period *t*;
- *LL* is the loss (%) on interconnector *n* in country *y'*;
- *IC* is the capacity (MW) of each interconnector *n* between country *y* and *y'*;
- *Y* equals the number of countries in the region (in this case 12);
- *Y'* equals the number of countries in the region minus 1 (in this case 11);

- $I$ equals the number of power plants in each country $y$.

Furthermore, we apply a security of supply constraint, shown below in (3), to each country in the form of a capacity requirement, which is similar to that applied in some wholesale electricity markets, such as Great Britain and PJM of the United States. The capacity requirement helps to mitigate the effect on generation investments of the model understating variation in demand and supply. Power sector simulation modelling requires trade-offs to ensure the model is computationally tractable while providing useful insights. It is computationally intensive to model stochastic variables such as demand, VRE generation availability and conventional generation outages or to model storage, which can be used to mitigate the effects of variation in electricity demand and supply. Given that the focus of Chapter 4 was on the long run effects of regional integration on the wholesale cost of supply under different electricity access scenarios in the SAPP region, we had to trade off a longer planning horizon and generation and transmission investment decision making against other features such as a more detailed representation of intermittent generation and hydro storage, with the effect of understating variation in demand and supply.

Without a capacity requirement the model would therefore tend to under-invest in generation capacity compared to the real world and would tend to understate power system costs. The capacity requirement in the model is that each country must have reliability adjusted installed generation capacity plus interconnector import capacity equal to at least 105% of demand or incur a penalty for having a capacity shortfall.

The security of supply constraint in each country in each period $t$ (i.e. for each year) is defined as follows:

$$\sum_{i=1}^{I}(G_{iyt}\,CC_i) + \sum_{n=1}^{N} IC_{nyt}(1 - LL_n)CC_n \geq DP_{yt}(1 + CR)\ \forall y, \forall t \qquad (3)$$

where:

- $G$ is the installed power plant capacity (MW) as defined in (1) in period $t$;
- $CC$ is the capacity credit (%) for each power plant $i$ or interconnector $n$, as applicable[63];
- $IC$ is the capacity (MW) of each interconnector able to import electricity into country $y$ in period $t$ as defined in (2);

[63] Capacity credit reflects the share of capacity that can be expected to be available during times of peak demand.

- *LL* is the loss (%) on transmission line *n* as defined in (2);
- *DP* is the peak gross demand (MW) in country *y* in period *t;*
- *CR* is the capacity requirement (%).

We use US$2018 1.0 million per MW for the penalty. This is higher than the annuitized capital cost of thermal plants (e.g. a coal fired steam turbine has an annuitized capital cost of $290,000 per MW), and therefore incentivises the model to build sufficient capacity while not being so high that it would dominate other model results if there were insufficient capacity. Each type of generator is assigned a capacity credit that reflects the likelihood of the power plant being available to meet peak demand. Dispatchable power plants have a higher capacity credit than non-dispatchable plants, for example, thermal power plants have a capacity credit of 85%, reflecting their expected availability, and solar photovoltaics (PV) a capacity credit of 5% in line with IRENA (2013) reflecting their high sensitivity to overcast conditions and their limited output in the early evening when demand is high.

Furthermore, we apply constraints on the options for developing generation capacity over time to reflect the ability of a country to mobilise resources and to reflect the availability of hydro generation development projects, which are site specific. For this, we work with a set of site-specific hydro generation projects and a set of generic projects for other generation technologies. We set a maximum capacity of each generic project that can be developed in each year. Finally, we also restrict the availability of some fuel types to reflect the natural endowment of resources for each country and the ability to import fuel, e.g. access to natural gas, access to liquefied natural gas (LNG), and access to coal. For example, currently gas is unavailable to the power sector in South Africa aside from a small amount imported from Mozambique which is used by an industrial firm (Sasol). However, in 2019 the upstream oil and gas company Total discovered potentially commercial quantities of gas 175km off the Southern coast (Quekeleshe, 2019) and we assume that this gas becomes available to the South African power sector from 2030.[64]

To make the optimisation problem tractable, we represent the decision variables for new generation capacity and for generation capacity retirement as continuous variables. The optimisation problem is therefore linear, which is a special form of convex problem

[64] The time required to assess and develop the gas and oil discoveries is uncertain. We assume a relatively long development period given the difficult offshore conditions encountered by Total and the lack of gas production in South Africa to date, suggesting that it may take some time to work through technical, political and legal issues before the discovery is appraised, a field development plan is agreed, and the discovery is commercialised.

and an optimal solution is guaranteed. The optimisation problem described above is a classical power sector least cost expansion and operation planning model, which is developed in General Algebraic Modelling System (GAMS), a widely used language for matrix algebra and mathematical programming, using CPLEX as the solver.

# Annex 4: Power system data

The following tables and graphs set out the power system data used in the generation investment and despatch optimisation model.

**Generation capacity, costs and technical characteristics**

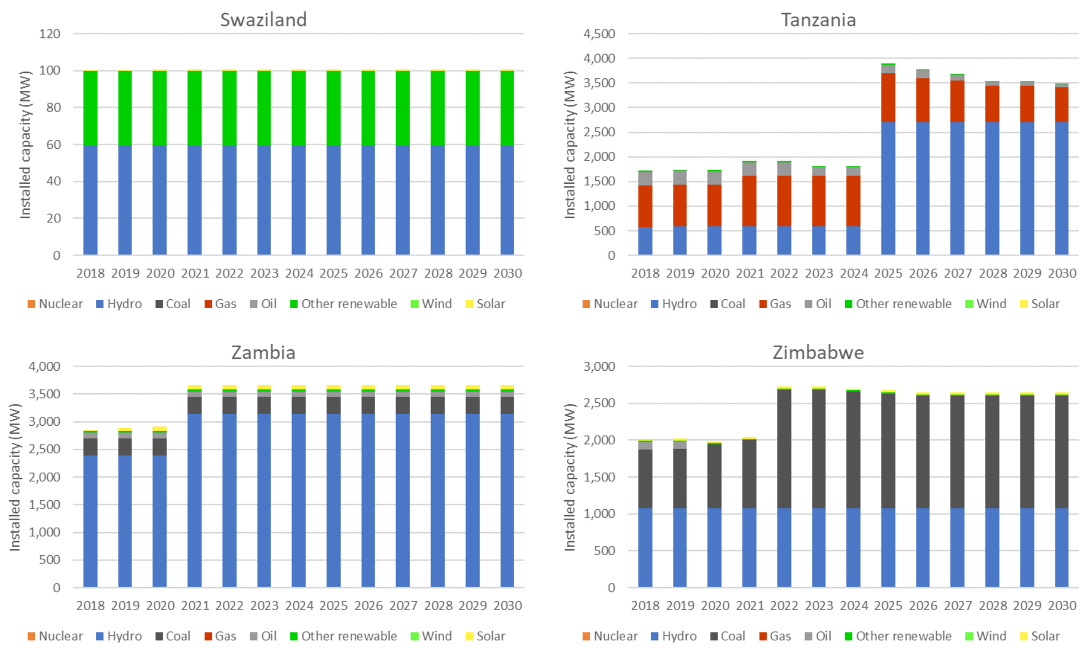
The simulation model begins with the countries' existing generation capacity adjusted downwards for any permanent derating as at 2018. We relied on data from African Energy (2019) for the installed capacity of existing power stations and power stations under construction in nine countries in the SAPP region whose power systems are interconnected (Botswana, Democratic Republic of Congo, Lesotho, Mozambique, Namibia, Swaziland, Zambia and Zimbabwe).[65]

We complemented the data from African Energy (2019) with data obtained by reviewing utility annual reports and generation master plans, where available, including for the three countries of the SAPP region for which we did not have data from African Energy (2019), i.e. the currently non-interconnected countries: Angola, Malawi and Tanzania. We excluded generation embedded within end user sites and off grid generation. Angola is different from the other countries because it currently has several separate electricity networks within the country, which it plans to interconnect by 2025. We therefore treat the Angolan grids as though they were part of a single interconnected grid from 2018.

The generation data provided by African Energy are commercially confidential. Therefore, we cannot list the data but rather show summary graphs of installed capacity (taking account of any permanent plant derating) by fuel type and by country. **Figure 16** and **Figure 17** show installed capacity for existing power plants and committed power plant projects (i.e. new capacity that has reached final investment decision or capacity already under construction), taking account of any scheduled decommissioning of existing power plants.

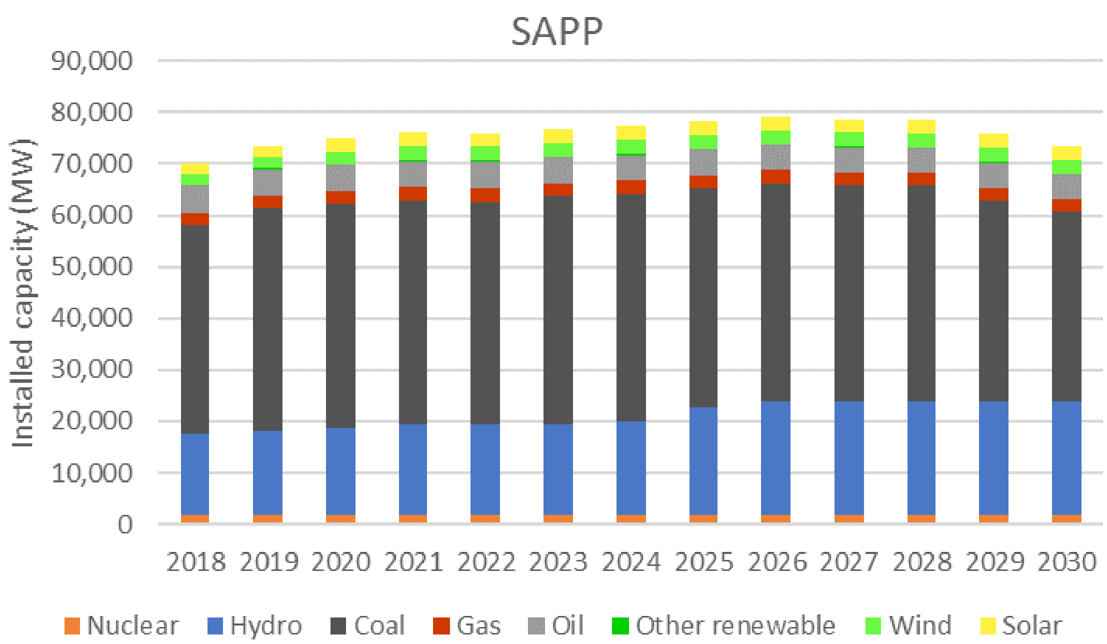
[65] We purchased data about power stations from African Energy (2019) for the nine currently interconnected countries of the SAPP region. These data include power plants directly connected to the transmission and distribution grids of each country, power plants embedded within a customer site that is connected to the grid, and power plants that are not connected to the main grid. We only consider power plants directly connected to the transmission and distribution grids in the model and represent demand consistently.

**Figure 16: Existing and committed installed generation capacity for each country in SAPP**




*Source: Authors based on African Energy (2019), utility annual reports and power system masterplans and integrated reports.*
*Note: Installed capacity has been adjusted for permanent derating of power plants. Capacity includes existing power plants, committed power plant projects and planned closures. The reader should be aware of the different y-axis scales of the graphs.*

**Figure 17: Aggregate existing and committed installed generation capacity in SAPP region**




*Source: Ibid.*
*Note: Ibid.*

Many countries rely on hydro generation for a large part of their electricity supply. However, South Africa, Botswana and Zimbabwe rely on coal for a large part of their generation. Since South Africa has by far the largest power system in the region, the predominant fuel in the region for power generation is coal, followed by hydro generation and then oil and gas. Angola, Tanzania, Mozambique and South Africa all have gas resources and we therefore expect to see more gas fired generation in future. Many countries have hydro resources that are as yet not fully exploited such as Angola, DRC, Mozambique, Namibia, Zambia, Zimbabwe, and we expect to see more hydro generation in future. Finally, many countries have a very good solar resource potential and a few countries have a good wind generation potential, and we therefore expect to see the development of more of these types of intermittent renewable generation in future.

The optimisation model can choose to build new generation capacity from a list of specific projects and from among generic projects form the overall set of candidate power plant projects. In the case of hydro and geothermal, candidate projects are site-specific projects that have been identified and are listed as candidate projects. In the case of other generation technologies, candidate projects are those specific projects already under construction or for which the final investment decision has been taken, and generic power plants since these projects tend not to be site specific. We allow the generation optimisation model the flexibility to adjust to the different electricity access and trade scenarios, which means treating committed plants not yet built as uncommitted (to allow the model to develop capacity in line with the status quo scenario which would generally have a level of demand below that in utility planning documents) and allowing the model to develop generic generation more quickly than the construction period would allow in practice (to allow the model to develop capacity in line with the higher access rate scenarios which would generally have a level of demand above that in utility planning documents). We do this to better reflect the overall generation cost of serving incremental household customers. What this means is that we do not apply the minimum construction period to generic candidate projects (**Table 20**) but rather assume the generation project can be built overnight if required to meet the specified demand. Nevertheless, we apply the capital expenditure adjustment related to financing during construction set out in **Table 21** to new generation projects, even for those projects for which we do not apply the minimum construction period. Furthermore, we allow for generation projects not to be built even if already committed. We do so since we are interested in understanding the efficient level of costs.

**Table 20: Generic candidate power plant projects**

| Technology | Construction period (Years) | Fuel type |
|---|---|---|
| OCGT | 2 | Gas |
| CCGT | 3 | Gas |
| ICE | 1 | HFO |
| Coal ST | 4 | Coal |
| Solar CSP | 4 | Solar |
| Solar PV | 1 | Solar |
| Solar with storage | 2 | Solar |
| Onshore Wind | 3 | Wind |

*Source: EPRI (2017) for the construction period.*
*Note: ICE means internal combustion engine. ST means steam turbine.*

Where available for committed power plants we use project specific information for the power plant capital cost. Where this is expressed as the overnight construction cost, we adjust it upwards for financing during construction (FDC) using the same 6% p.a. real discount rate that we apply throughout the model and using the construction expenditure profile set out in **Table 22**. Where project specific information is not available, we use generic power plant capital costs, expressed in US$2018. In the case of concentrated solar power (CSP), solar PV, PV with storage and wind we apply a real learning rate such that the capital cost per MW falls over time. We apply the learning rate only to 2030, assuming that costs remain constant in real terms thereafter.

**Table 21: Generic power plant capital costs and lifetime**

| Technology | Capital cost in 2018 (US$/kW) | Learning rate (per year) | Multiplier on capital cost for FDC | Economic life (years) | Gross efficiency, LHV (2020) |
|---|---|---|---|---|---|
| OCGT | 813 | | 1.09 | 30 | 38% |
| CCGT | 1,037 | | 1.11 | 30 | 58% |
| ICE | 1,110 | | 1.03 | 30 | 42% |
| Coal ST | 2,315 | | 1.11 | 40 | 46% |
| Geothermal | 4,000 | | 1.15 | 30 | 100% |
| Small hydro | 4,192 | | 1.13 | 50 | 100% |
| Large hydro | 3,068 | | 1.23 | 50 | 100% |
| Pumped hydro storage | 3,068 | | 1.23 | 50 | 100% |
| Solar CSP | 3,924 | -3.75% | 1.11 | 30 | 100% |
| Solar PV | 1,210 | -8.09% | 1.03 | 25 | 100% |
| Solar with storage | 6,510 | -3.93% | 1.11 | 30 | 100% |
| Onshore Wind | 1,736 | -1.29% | 1.04 | 20 | 100% |
| Biomass | 4,152 | | 1.11 | 30 | 25% |
| Nuclear | 6,275 | | 1.21 | 60 | 36% |

*Source: SAPP Pool Plan (2017) for most capital costs, which we adjust for inflation from 2017 to 2018 to express costs in US$2018 and which we further adjust by the learning rate from 2017 to 2018 in the case of solar and wind generation. We assume pumped hydro storage has the same capital cost as large hydro. Since the costs of solar PV are rapidly changing, with learning rates exceeding expectations, we did not rely on SAPP Pool Plan (2017) for capital costs of solar PV but instead took the solar PV global average capex cost for 2018 reported by IRENA (2019a) to which we applied an 8.09% per commissioning year cost reduction. We note that there is wide variation between the costs of solar PV projects globally, partly driven by the solar resource and partly driven by other factors such as project WACC, development expenses and procurement process (tender or auction versus negotiated agreement). Today, the cost of solar PV in SSA remains substantially above those that we observe in Europe or Latin America, despite good resource potential (IEA, 2019a). The capital cost of geothermal also reflects the global average cost for 2018 reported by IRENA (2019a). The learning rate is calculated from IRENA (2016). The multiplier on capital cost for financing during construction is based on the construction expenditure profile shown in **Table 22**, applying a 6% real discount rate. Power plant efficiency has generally improved over time according to commissioning year and we follow this trend for existing and new power plants. The efficiency shown in this table is for a plant commissioned in 2020, as indicated. FDC is financing during construction.*

**Table 22: Construction expenditure profile**

| Technology | Years prior to commissioning | | | | | | |
|---|---|---|---|---|---|---|---|
| | 7 | 6 | 5 | 4 | 3 | 2 | 1 |
| OCGT | | | | | | 90% | 10% |
| CCGT | | | | | 40% | 50% | 10% |
| ICE | | | | | | | 100% |
| Coal ST | | | | 10% | 25% | 45% | 20% |
| Geothermal | | | | 30% | 30% | 30% | 10% |
| Small hydro | | | | 25% | 25% | 25% | 25% |
| Large hydro | 14% | 14% | 14% | 14% | 14% | 14% | 14% |
| Pumped hydro storage | 14% | 14% | 14% | 14% | 14% | 14% | 14% |
| Solar CSP | | | | 10% | 25% | 45% | 20% |
| Solar PV | | | | | | | 100% |
| Solar with storage | | | | 10% | 25% | 45% | 20% |
| Onshore Wind | | | | | 5% | 5% | 90% |
| Biomass | | | | 10% | 25% | 45% | 20% |
| Nuclear | | 15% | 15% | 25% | 25% | 10% | 10% |

*Source: EPRI (2017), with the exception of geothermal which is based on the timing for the phases of development from the pre-feasibility report to operation as estimated from Flóvenz (undated).*
*Note: ICE means internal combustion engine. ST means steam turbine.*

The ability to build a particular type of power plant in a country depends also upon the availability of the related primary energy source, which could either be an indigenous source or be imported, which is discussed further below when we discuss fuel prices and availability of primary fuels.

**Table 23: Maximum development of generic candidate projects each year (MW)**

| Technology | OCGT | CCGT | ICE | Coal ST | CSP | Solar PV | Solar with storage | On-shore wind |
|---|---|---|---|---|---|---|---|---|
| Angola | 100 | 200 | 100 | 400 | 100 | 100 | 100 | 100 |
| Botswana | | | 100 | 400 | 100 | 100 | 100 | 100 |
| DRC | 100 | 200 | 100 | 400 | 100 | 100 | 100 | 100 |
| eSwatini | | | 50 | 200 | 25 | 25 | 25 | 25 |
| Lesotho | | | 50 | | 25 | 25 | 25 | 25 |
| Malawi | | | 50 | 200 | 50 | 50 | 50 | 50 |
| Mozambique | 100 | 200 | 100 | 400 | 100 | 100 | 100 | 100 |
| Namibia | 100 | 200 | 100 | 400 | 100 | 100 | 100 | 100 |
| South Africa | 400 | 800 | 400 | 1600 | 400 | 400 | 400 | 400 |
| Tanzania | 100 | 200 | 100 | 400 | 100 | 100 | 100 | 100 |
| Zambia | | | 100 | 400 | 100 | 100 | 100 | 100 |
| Zimbabwe | | | 100 | 400 | 100 | 100 | 100 | 100 |

*Source: Authors assumptions based on size of power sector.*
*Note: ICE means internal combustion engine. The size is the maximum capacity of each generic type of power plant able to be built in each country in a year on average over time. In the model, fuel availability also potentially limits the construction of certain power generation technologies. Solar CSP with storage has 6 hours of storage.*

**Table 24: Other generic power plant cost and technical characteristics**

| Technology | Annual fixed O&M cost (US$/kW) | Variable O&M cost (US$/MWh) | Own use | Planned outage rate | Forced outage rate | Overall availability | Capacity credit |
|---|---|---|---|---|---|---|---|
| OCGT | 13.64 | 0.20 | 0.8% | 6.9% | 4.6% | 89% | 85% |
| CCGT | 14.09 | 1.86 | 2.5% | 6.9% | 4.6% | 89% | 85% |
| ICE | 40.39 | 10.24 | 1.8% | 6.9% | 4.6% | 89% | 85% |
| Gas / oil ST | 59.45 | 4.97 | 5.0% | 4.8% | 3.7% | 92% | 85% |
| Coal ST | 92.61 | 6.80 | 7.7% | 4.8% | 3.7% | 92% | 85% |
| Geothermal | 122.28 | - | 5.0% | 4.8% | 3.7% | 92% | 85% |
| Small hydro | 40.85 | 1.36 | - | 0.0% | 0.0% | n/a | 50% |
| Large hydro | 40.85 | 1.36 | - | 0.0% | 0.0% | n/a | 80% |
| Pumped hydro storage | 40.85 | 1.36 | - | 0.0% | 0.0% | n/a | 85% |
| Solar CSP | 84.62 | 0.08 | - | 0.0% | 5.0% | n/a | 5% |
| Solar PV | 22.76 | - | - | 0.0% | 1.0% | n/a | 5% |
| Solar with storage | 89.29 | 0.07 | - | 0.0% | 5.0% | n/a | 30% |
| Onshore Wind | 53.50 | - | - | 0.0% | 4.5% | n/a | 20% |
| Biomass | 140.76 | 5.63 | 7.7% | 4.0% | 6.0% | 90% | 85% |
| Nuclear | 94.49 | 2.35 | 7.7% | 2.5% | 5.5% | 92% | 85% |

*Source: O&M costs – EPRI (2017) converted from ZAR to US$ using the exchange rate reported by EPRI as at 1 January 2017 and inflated to 2018 costs, with the exception of geothermal and hydro which are sourced from EIA (2019b). Own use – calculated from the difference between gross and net efficiency from EPRI (2017) for OCGT, CCGT, ICE and Coal ST. We assume nuclear and biomass own use are similar to coal ST, and geothermal own use is between coal ST and CCGT. Outage rates – EPRI (2017) for OCGT, CCGT, Coal ST, biomass and nuclear. We assume gas / oil ST and biomass are the same as coal ST. Hydro, solar and wind availability is driven by the water, solar and wind resource availability. Capacity credit – IRENA (2013) for wind and solar PV, other capacity credits are assumptions.*
*Note: ICE means internal combustion engine. O&M means operations and maintenance. ST means steam turbine.*

Power plant fuel conversion efficiencies are shown in **Table 25**.

**Table 25: Gross power plant efficiency (LHV)**

| Technology | 1960 | 1970 | 1980 | 1990 | 2000 | 2010 | 2020 | 2030 | 2040 |
|---|---|---|---|---|---|---|---|---|---|
| OCGT | | | 30% | 30% | 34% | 36% | 38% | 40% | 41% |
| CCGT | | | | 44% | 50% | 55% | 58% | 60% | 62% |
| ICE | 42% | 42% | 42% | 42% | 42% | 42% | 42% | 42% | 42% |
| Coal ST | 33% | 35% | 37% | 39% | 41% | 43% | 46% | 49% | 52% |
| Gas/Oil ST | 35% | 37% | 39% | 41% | 43% | | | | |
| Biomass | 17% | 17% | 17% | 19% | 21% | 23% | 25% | 27% | 30% |
| Nuclear | 25% | 25% | 27% | 29% | 31% | 33% | 36% | 39% | 42% |

*Source: Kaderják (2007), with the exception of ICE and biomass which are calculated from EPRI (2017) by converting the net heat rate (kJ/kWh) to net efficiency (%) and then to gross efficiency (%). We lag the improvement in efficiencies by 10 years to reflect the use of older generation technologies in SSA.*
*Note: ST means steam turbine, LHV means low heating value. We assume that the efficiencies are LHV, given the level of efficiencies. We use linear interpolation to obtain efficiencies between the years shown.*

## Renewable generation

Renewable generation, with the exception of biomass, is assumed to have a zero-fuel cost and maximum hourly availability that is driven by the resource availability. The seasonal and hourly maximum availability profiles of hydro generation are assumed to be the same for all countries. Maximum hourly availability profiles for wind, solar PV, CSP, and CSP with storage are country specific. We describe below the derivation of renewable availability profiles.

We note that although the output of solar and wind variable renewable energy (VRE) sources is modelled as deterministic profiles (not stochastic profiles), the profiles do show variation from hour to hour, day to day, and country to country. Therefore, the ability to trade electricity between countries does help the regional power system to manage the varying VRE output in each country.

*Solar PV*

Maximum availability profiles for solar PV are derived from the European Commission's Photovoltaic Geographical Information System (EC, 2019). This tool has historic hourly data on solar radiation for different locations. Using this tool we downloaded hourly data for the nominal output of solar PV plants for the 10-year period from 2007 to 2016, for a fixed mount plant with optimised slope and azimuth. We downloaded data for three sites from each of the 12 countries, selecting sites that are relatively close to population centres, implying that the sites would be relatively close to the grid. To derive an hourly PV output for a year for each country in the SAPP region, we averaged the nominal output across the three sites and across the 10 years. The EC's tool expresses PV output according to Greenwich Mean Time (GMT) and we therefore adjusted the profiles by 2 hours to express them all in South African time. The resultant annual capacity factors for PV from each country are shown in **Table 26**, based on $kWh_{[ac]}$ relative to kWp.[66]

**Table 26: Capacity factors for solar PV profiles**

| Country | Annual capacity factor |
|---|---|
| Angola | 19.3% |
| Botswana | 20.9% |
| DRC | 19.9% |
| Lesotho | 19.4% |
| Malawi | 19.4% |
| Mozambique | 19.7% |
| Namibia | 20.7% |
| South Africa | 19.9% |
| eSwatini | 18.4% |
| Tanzania | 20.5% |
| Zambia | 20.3% |
| Zimbabwe | 20.7% |

*Source: Authors based on EC (2019)*

We selected the hourly data from the PV output profile corresponding to the same periods that we use to represent demand in the generation optimisation model. We show the PV output data for the first day of each of the four sample weeks for each of the

[66] kWp refers to a standard measure of the peak output from a solar PV panel, measured under standard conditions, including temperature and irradiation.

12 countries in **Figure 18**, using graduated red shading to highlight the hours with highest output.

**Figure 18: Solar PV profile**

| Country | Week | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| South Africa | 1 | 0% | 0% | 0% | 0% | 0% | 5% | 20% | 38% | 56% | 63% | 70% | 72% | 66% | 51% | 35% | 22% | 10% | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| South Africa | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 9% | 25% | 40% | 49% | 54% | 51% | 47% | 36% | 25% | 8% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| South Africa | 3 | 0% | 0% | 0% | 0% | 0% | 3% | 17% | 36% | 50% | 62% | 68% | 67% | 59% | 51% | 36% | 17% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| South Africa | 4 | 0% | 0% | 0% | 0% | 2% | 14% | 33% | 49% | 63% | 72% | 78% | 74% | 70% | 57% | 41% | 28% | 14% | 4% | 0% | 0% | 0% | 0% | 0% | 0% |
| Lesotho | 1 | 0% | 0% | 0% | 0% | 0% | 3% | 25% | 43% | 59% | 67% | 77% | 75% | 47% | 31% | 18% | 9% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Lesotho | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 4% | 28% | 45% | 57% | 59% | 57% | 51% | 39% | 25% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Lesotho | 3 | 0% | 0% | 0% | 0% | 0% | 3% | 23% | 42% | 60% | 67% | 65% | 58% | 53% | 41% | 28% | 12% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Lesotho | 4 | 0% | 0% | 0% | 0% | 1% | 19% | 35% | 47% | 65% | 71% | 76% | 65% | 66% | 50% | 36% | 22% | 9% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Swaziland | 1 | 0% | 0% | 0% | 0% | 0% | 6% | 20% | 38% | 50% | 59% | 69% | 65% | 60% | 51% | 38% | 16% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Swaziland | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 16% | 41% | 56% | 62% | 67% | 63% | 55% | 43% | 26% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Swaziland | 3 | 0% | 0% | 0% | 0% | 0% | 8% | 24% | 38% | 50% | 59% | 62% | 60% | 55% | 43% | 28% | 11% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Swaziland | 4 | 0% | 0% | 0% | 0% | 4% | 10% | 23% | 35% | 46% | 54% | 56% | 52% | 49% | 36% | 24% | 11% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Zimbabwe | 1 | 0% | 0% | 0% | 0% | 0% | 15% | 35% | 43% | 53% | 62% | 61% | 64% | 47% | 41% | 23% | 11% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Zimbabwe | 2 | 0% | 0% | 0% | 0% | 0% | 4% | 31% | 49% | 62% | 66% | 64% | 58% | 46% | 33% | 16% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Zimbabwe | 3 | 0% | 0% | 0% | 0% | 0% | 20% | 44% | 60% | 71% | 79% | 76% | 70% | 57% | 40% | 19% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Zimbabwe | 4 | 0% | 0% | 0% | 0% | 4% | 17% | 35% | 45% | 52% | 60% | 58% | 56% | 46% | 32% | 15% | 6% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Botswana | 1 | 0% | 0% | 0% | 0% | 0% | 9% | 20% | 34% | 49% | 50% | 65% | 62% | 57% | 47% | 30% | 16% | 6% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Botswana | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 17% | 36% | 47% | 55% | 59% | 59% | 53% | 42% | 26% | 9% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Botswana | 3 | 0% | 0% | 0% | 0% | 0% | 8% | 23% | 37% | 52% | 63% | 71% | 69% | 64% | 52% | 33% | 13% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Botswana | 4 | 0% | 0% | 0% | 0% | 2% | 13% | 30% | 46% | 59% | 66% | 66% | 59% | 57% | 43% | 27% | 13% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Mozambique | 1 | 0% | 0% | 0% | 0% | 1% | 11% | 24% | 40% | 39% | 46% | 48% | 48% | 49% | 40% | 25% | 10% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Mozambique | 2 | 0% | 0% | 0% | 0% | 0% | 12% | 28% | 42% | 58% | 58% | 53% | 55% | 45% | 34% | 18% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Mozambique | 3 | 0% | 0% | 0% | 0% | 1% | 23% | 38% | 51% | 58% | 64% | 63% | 61% | 50% | 37% | 20% | 6% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Mozambique | 4 | 0% | 0% | 0% | 0% | 8% | 22% | 35% | 45% | 50% | 51% | 52% | 50% | 43% | 31% | 18% | 7% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Zambia | 1 | 0% | 0% | 0% | 0% | 0% | 10% | 27% | 50% | 58% | 66% | 66% | 58% | 49% | 37% | 23% | 10% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Zambia | 2 | 0% | 0% | 0% | 0% | 0% | 7% | 32% | 49% | 64% | 65% | 66% | 61% | 54% | 38% | 22% | 5% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Zambia | 3 | 0% | 0% | 0% | 0% | 0% | 19% | 45% | 63% | 74% | 79% | 80% | 74% | 62% | 45% | 24% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Zambia | 4 | 0% | 0% | 0% | 0% | 2% | 11% | 26% | 35% | 46% | 53% | 58% | 47% | 43% | 26% | 17% | 6% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Namibia | 1 | 0% | 0% | 0% | 0% | 0% | 0% | 11% | 30% | 50% | 61% | 71% | 68% | 62% | 46% | 36% | 21% | 10% | 2% | 0% | 0% | 0% | 0% | 0% | 0% |
| Namibia | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 23% | 40% | 53% | 59% | 61% | 57% | 47% | 33% | 15% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Namibia | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 17% | 39% | 58% | 68% | 72% | 74% | 68% | 56% | 41% | 23% | 7% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Namibia | 4 | 0% | 0% | 0% | 0% | 0% | 9% | 27% | 50% | 64% | 74% | 72% | 70% | 65% | 55% | 38% | 30% | 14% | 4% | 0% | 0% | 0% | 0% | 0% | 0% |
| Angola | 1 | 0% | 0% | 0% | 0% | 0% | 0% | 3% | 9% | 24% | 33% | 51% | 55% | 44% | 52% | 41% | 30% | 10% | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| Angola | 2 | 0% | 0% | 0% | 0% | 0% | 0% | 12% | 36% | 53% | 66% | 72% | 73% | 69% | 59% | 45% | 26% | 8% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Angola | 3 | 0% | 0% | 0% | 0% | 0% | 0% | 18% | 37% | 57% | 68% | 76% | 76% | 68% | 58% | 43% | 21% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Angola | 4 | 0% | 0% | 0% | 0% | 0% | 2% | 9% | 24% | 36% | 45% | 56% | 57% | 53% | 43% | 32% | 19% | 6% | 2% | 0% | 0% | 0% | 0% | 0% | 0% |
| DRC | 1 | 0% | 0% | 0% | 0% | 0% | 7% | 11% | 30% | 34% | 45% | 54% | 46% | 46% | 32% | 17% | 8% | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| DRC | 2 | 0% | 0% | 0% | 0% | 0% | 4% | 31% | 51% | 64% | 72% | 73% | 70% | 60% | 45% | 27% | 8% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| DRC | 3 | 0% | 0% | 0% | 0% | 0% | 13% | 40% | 60% | 73% | 80% | 80% | 75% | 65% | 49% | 29% | 8% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| DRC | 4 | 0% | 0% | 0% | 0% | 0% | 6% | 21% | 36% | 47% | 53% | 48% | 52% | 39% | 29% | 19% | 8% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Malawi | 1 | 0% | 0% | 0% | 0% | 1% | 13% | 28% | 44% | 55% | 60% | 66% | 61% | 45% | 24% | 16% | 7% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Malawi | 2 | 0% | 0% | 0% | 0% | 0% | 15% | 26% | 40% | 50% | 53% | 51% | 51% | 42% | 31% | 17% | 6% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Malawi | 3 | 0% | 0% | 0% | 0% | 0% | 25% | 46% | 65% | 72% | 76% | 76% | 69% | 57% | 41% | 20% | 5% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Malawi | 4 | 0% | 0% | 0% | 0% | 6% | 16% | 31% | 41% | 49% | 51% | 50% | 49% | 41% | 27% | 15% | 5% | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Tanzania | 1 | 0% | 0% | 0% | 0% | 1% | 14% | 34% | 54% | 67% | 73% | 77% | 69% | 60% | 44% | 28% | 8% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Tanzania | 2 | 0% | 0% | 0% | 0% | 0% | 15% | 35% | 52% | 62% | 68% | 69% | 64% | 54% | 39% | 20% | 3% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Tanzania | 3 | 0% | 0% | 0% | 0% | 2% | 25% | 46% | 61% | 72% | 76% | 76% | 71% | 61% | 44% | 23% | 4% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Tanzania | 4 | 0% | 0% | 0% | 0% | 5% | 18% | 34% | 51% | 62% | 67% | 70% | 64% | 55% | 38% | 21% | 5% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

*Source: Authors based on EC (2019)*
*Note: Here we show the PV output profile for the first day of each sample week for each country in the SAPP region.*

Angola and Namibia are on the West Coast of Africa and therefore have solar profiles whose output tends to be delayed compared to other countries. Conversely, countries on the East Coast – eSwatini, Mozambique, Malawi, Tanzania – have profiles whose output tends to be slightly advanced of other countries.

*Concentrated Solar Power (CSP)*

We derive the output profile for CSP without storage and solar with 6 hours storage from the profile for PV. In the case of CSP without storage, EPRI (2017) notes that the capacity factor for CSP with a parabolic trough in South Africa would have a capacity factor of 25.6%, which is 28.6% greater than the capacity factor for solar PV in South Africa. We therefore multiply the output in each hour from our solar PV profile for each country by 1.286 to obtain the CSP (without storage) output profile.

EPRI (2017) notes that CSP with 6 hours storage in South Africa would have a capacity factor of 38.0%. We therefore add output in the period from 3pm to 11pm to the output profile for CSP without storage to increase its capacity factor to 38% to obtain the output profile for CSP with 6 hours storage.[67]

*Onshore wind*

For onshore wind we derived an hourly wind profile for the year for South Africa, Mozambique and Zambia, and mapped those three profiles to the remaining nine countries in the SAPP region. We estimated the capacity factor for each country by first taking the average wind speed for the 10th percentile of windiest sites in each country retrieved from Global Wind Atlas (2019).[68] We then relied on Wu (2015) to map average wind speeds to annual capacity factor for each country, as shown in **Table 27**. Finally, we adjusted the hourly wind profile to match the capacity factor for each country. The hourly profile for South Africa was derived from Knorr et al. (2016), the hourly profile for Mozambique from JICA (2018a) and the hourly profile for Zambia from DNV GL (2018).

**Table 27: Capacity factors for wind profiles**

| Country | Annual capacity factor |
|---|---|
| Angola | 22.2% |
| Botswana | 29.9% |
| DRC | 16.4% |
| Lesotho | 39.6% |
| Malawi | 26.9% |
| Mozambique | 25.8% |
| Namibia | 36.0% |
| South Africa | 37.2% |
| eSwatini | 27.2% |
| Tanzania | 28.8% |
| Zambia | 24.2% |
| Zimbabwe | 26.6% |

*Source: Our calculations based on wind speeds for the 10th percentile of windiest sites in each country as obtained from Global Wind Atlas (2019) and mapped to capacity factors using Wu (2015).*

*Hydro profiles*

For existing and candidate hydro power stations, we use the plant specific average capacity factor as described in regional planning documents where available IRENA (2013). However, where this information is unavailable, we assumed a 45% capacity factor, as adopted by Castellano et al. (2015). To keep the generation optimisation model

67 There is no single correct adjustment to the output profile for CSP without storage to obtain the output profile for CSP with 6 hours storage. Broadly, we would expect the additional output to come during the evening of each day, while there is high demand for electricity and before the energy from the stored heat dissipates.

68 Our logic for using the 10th percentile of windiest sites is that wind turbines will tend to be located in the better (windiest) sites in a country although due to terrain restrictions or distance from the grid, the very best sites may not be practical to utilise. Therefore, we assume only that very good wind sites are available to be used.

tractable, we do not optimise the output of hydro generation. Rather, we assume that output from hydro during the wet season is 120% of the annual average and 80% of the annual average during the dry season. This means that average output during the wet season is 50% higher than during the dry season, while maintaining the average annual capacity factor.

Run of river hydro power stations have a very limited range of usable water storage, which means that they generate according to river flows. Therefore, we assume that these types of hydro power plants have on average a flat output profile during the day. Conversely, hydro power stations with a range of usable water storage can control the release of water so as to generate more during peak demand periods and less during off peak demand periods. Therefore, we assume that hydro power stations with usable storage generate up to 120% of their average hourly output over the day during the morning and evening peak and 70% of their average hourly output over the day from midnight to 6am, while maintaining the seasonal capacity factor over the day as a whole.

Pumped hydro storage plants are able to use electricity to pump water between a lower reservoir and upper reservoir and generate electricity by releasing water from the upper reservoir into the lower reservoir. Typically pumped hydro storage plants would pump at night during low demand periods and generate during the high demand periods. We do not optimise the operation of pumped hydro storage and instead assume that they generate for 3 hours in the morning and 3 hours in the evening each day.

**Candidate large hydro projects**

We list large candidate hydro projects in the subsequent tables, with their characteristics and estimated earliest commissioning year based on standard construction periods.

**Table 28: Candidate large hydro projects (Angola)**

| Plant name | Installed capacity (MW) | Earliest comm. Year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Zenzo | 950 | 2028 | Hydro | 45% | 3,907 |
| Tumulo do Cacador | 453 | 2028 | Hydro | 45% | 2,993 |
| Cafula | 403 | 2028 | Hydro | 45% | 3,623 |
| Benga | 987 | 2028 | Hydro | 45% | 3,907 |
| Quilengue | 217 | 2028 | Hydro | 45% | 3,907 |
| Carianga | 381 | 2028 | Hydro | 45% | 4,427 |
| Bembeze | 260 | 2028 | Hydro | 45% | 3,847 |
| Quissonde | 121 | 2028 | Hydro | 45% | 9,020 |
| Cuteca | 203 | 2028 | Hydro | 45% | 4,709 |
| Lomaum extension | 160 | 2028 | Hydro | 33% | 3,134 |
| Calangue | 190 | 2028 | Hydro | 45% | 3,229 |
| Quissuca | 121 | 2028 | Hydro | 45% | 6,103 |
| Calindo | 58 | 2024 | ROR | 45% | 3,712 |
| Baynes | 300 | 2028 | Hydro | 45% | 2,865 |
| Mucundi | 74 | 2024 | ROR | 45% | 8,371 |
| Jamb Ya Oma | 75 | 2024 | ROR | 45% | 7,676 |
| Jamb Ya Mina | 180 | 2028 | Hydro | 45% | 5,138 |
| Chicapa II extension | 100 | 2024 | ROR | 45% | 4,721 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river.*

**Table 29: Candidate large hydro projects (Democratic Republic of Congo)**

| Plant name | Installed capacity (MW) | Earliest comm. year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Inga III | 900 | 2028 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2028 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2028 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2028 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2029 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2030 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2031 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2032 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2033 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2034 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2035 | Hydro | 59% | 3,907 |
| Inga III | 900 | 2036 | Hydro | 59% | 3,907 |
| Mbimbi Mayi Munene | 100 | 2024 | ROR | 45% | 4,721 |
| Ruzizi III | 147 | 2028 | ROR | 45% | 3,907 |
| Ruzizi IV | 287 | 2028 | ROR | 45% | 3,907 |
| Sombwe | 148 | 2028 | ROR | 45% | 3,907 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river. We have split Inga III into several different projects, each of 900MW to allow staged development.*

**Table 30: Candidate large hydro projects (Lesotho)**

| Plant name | Installed capacity (MW) | Earliest comm. Year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Muela II | 110 | 2028 | ROR | 6% | 3,907 |
| Kobong PHS | 1,200 | 2028 | PHS | 45% | 3,907 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river. PHS means pumped hydro storage.*

**Table 31: Candidate large hydro projects (Malawi)**

| Plant name | Installed capacity (MW) | Earliest comm. Year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Kholombidzo | 219 | 2028 | ROR | 65% | 3,042 |
| Mpatamanga | 308 | 2028 | Hydro | 52% | 2,229 |
| Hamilton Falls | 87 | 2024 | ROR | 52% | 1,628 |
| Kapichira III | 110 | 2028 | ROR | 39% | 1,634 |
| Malenga | 63 | 2024 | ROR | 44% | 10,417 |
| Fufu | 261 | 2028 | Hydro | 49% | 3,503 |
| Lower Songwe | 90 | 2024 | Hydro | 44% | 3,339 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river.*

**Table 32: Candidate large hydro projects (Mozambique)**

| Plant name | Installed capacity (MW) | Earliest comm. Year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Boroma | 220 | 2028 | Hydro | 45% | 5,211 |
| Cahora Bassa North | 1,245 | 2028 | Hydro | 45% | 1,019 |
| Lupata | 600 | 2028 | Hydro | 45% | 3,174 |
| Massingir | 60 | 2024 | ROR | 45% | 4,721 |
| Mphanda Nkuwa | 1,500 | 2028 | Hydro | 45% | 1,872 |
| Pávua | 160 | 2028 | Hydro | 45% | 3,907 |
| Tsate | 50 | 2025 | ROR | 45% | 4,504 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river.*

**Table 33: Candidate large hydro projects (Namibia)**

| Plant name | Installed capacity (MW) | Earliest comm. Year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Baynes | 612 | 2028 | Hydro | 36% | 3,907 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river.*

**Table 34: Candidate large hydro projects (Swaziland)**

| Plant name | Installed capacity (MW) | Earliest comm. Year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Ngwempisi | 120 | 2028 | ROR | 45% | 3,907 |
| Zoetic | 200 | 2028 | Hydro | 45% | 3,907 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river. PHS means pumped hydro storage.*

**Table 35: Candidate large hydro projects (Tanzania)**

| Plant name | Installed capacity (MW) | Earliest comm. Year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Kakono | 87 | 2024 | ROR | 75% | 5,289 |
| Rumakali | 222 | 2028 | Hydro | 68% | 3,420 |
| Ruhudji | 358 | 2028 | Hydro | 64% | 2,523 |
| Songwe Manolo Lower | 178 | 2028 | Hydro | 44% | 3,576 |
| Songwe Sofre Middle | 159 | 2028 | Hydro | 42% | 3,996 |
| Mpanga | 160 | 2028 | Hydro | 57% | 3,562 |
| Masigira | 118 | 2028 | ROR | 64% | 3,002 |
| Lower Kihansi Expansion | 120 | 2028 | Hydro | 7% | 2,495 |
| Kikonge | 300 | 2028 | Hydro | 48% | 3,032 |
| Iringa Nginayo | 52 | 2024 | ROR | 58% | 2,892 |
| Mnyera Ruaha | 60 | 2024 | Hydro | 55% | 5,071 |
| Mnyera Mnyera | 137 | 2028 | ROR | 55% | 2,705 |
| Mnyera Kwanini | 144 | 2028 | ROR | 55% | 1,547 |
| Mnyera Pumbwe | 123 | 2028 | ROR | 55% | 2,418 |
| Mnyera Taveta | 84 | 2024 | ROR | 55% | 2,940 |
| Mnyera Kisingo | 120 | 2028 | ROR | 55% | 3,549 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river.*

**Table 36: Candidate large hydro projects (Zambia)**

| Plant name | Installed capacity (MW) | Earliest comm. Year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Batoka Gorge North | 1,200 | 2028 | ROR | 47% | 2,441 |
| Devil’s Gorge | 620 | 2028 | Hydro | 45% | 3,907 |
| Get FiT Round I | 100 | 2024 | ROR | 45% | 4,721 |
| Kabwelume Falls | 96 | 2024 | ROR | 45% | 4,721 |
| Kundabwika Falls | 156 | 2028 | ROR | 45% | 3,907 |
| Lufubu I | 163 | 2028 | Hydro | 45% | 3,907 |
| Lufubu II | 163 | 2028 | Hydro | 45% | 3,907 |
| Lusiwasi Lower | 86 | 2024 | ROR | 45% | 4,721 |
| Mambilima Falls I | 126 | 2028 | Hydro | 45% | 3,907 |
| Mambilima Falls II | 202 | 2028 | Hydro | 45% | 3,907 |
| Mambilima Falls V | 372 | 2028 | Hydro | 45% | 3,907 |
| Mkushi | 65 | 2024 | ROR | 45% | 4,721 |
| Mulembo Lelya | 330 | 2028 | Hydro | 45% | 3,907 |
| Mumbotuta Falls | 490 | 2028 | Hydro | 45% | 3,907 |
| Mwambwa | 75 | 2024 | ROR | 45% | 4,721 |
| Ndevu Gorge | 235 | 2028 | Hydro | 45% | 3,907 |
| New Africa Power | 65 | 2024 | ROR | 45% | 4,721 |
| Ngonye Falls | 60 | 2024 | ROR | 45% | 4,721 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river.*

**Table 37: Candidate large hydro projects (Zimbabwe)**

| Plant name | Installed capacity (MW) | Earliest comm. Year | Plant type | Capacity factor | Investment cost ($/kW) |
|---|---|---|---|---|---|
| Batoka Gorge South | 1,200 | 2028 | ROR | 47% | 2,441 |
| Devil's Gorge | 620 | 2028 | Hydro | 45% | 3,907 |
| Kondo | 270 | 2028 | Hydro | 45% | 1,475 |

*Source: Utility websites and annual reports, and generation master plans.*
*Note: ROR means run of river.*

*Geothermal*

**Table 38: Candidate geothermal projects**

| Plant name | Country | Installed capacity (MW) | Earliest comm. year | Investment cost ($/kW) |
|---|---|---|---|---|
| Bwengwa River | Zambia | 10 | 2024 | 4,581 |
| Mbeya 1 | Tanzania | 100 | 2024 | 4,581 |
| Mbeya 2 | Tanzania | 200 | 2024 | 4,581 |

*Source: Utility websites and annual reports, and generation master plans.*

## Fuel prices and availability

Thermal power plants convert energy from fuel into electricity at the efficiency or heat rate of the relevant power plant. In the model we express fuel prices as economic prices (without subsidies or taxes) in real terms and derive a base fuel price to which we apply price spreads for countries that need to import fuel. We also indicate whether a particular fuel type is available to be used by the power sector in each country, as indicated in **Table 39**. The ability to build a particular type of power plant in a country depends upon the availability of the related primary energy source, which could either be an indigenous source or be imported. We assume that natural gas is not available in Botswana, Lesotho, Malawi, eSwatini and Zambia. In South Africa, we assume that indigenous gas sources will not be available before 2030 and that prior to this date South Africa can import LNG. We assume coal is available in all countries with the exception of Lesotho. Biomass is available in all countries with the exception of Lesotho and Namibia. Geothermal is available only in Tanzania and Zambia. This is largely in line with IRENA (2013), with the exception of Zambia (we assume no gas is available) and South Africa (we assume indigenous gas is available from 2030).

**Table 39: Fuel available to the power sector**

| Country | Gas | LNG | Coal | Uranium | Diesel | HFO | Bio-mass | Geo-thermal |
|---|---|---|---|---|---|---|---|---|
| Angola | 1 | | 1 | | 1 | 1 | 1 | |
| Botswana | | | 1 | | 1 | 1 | 1 | |
| DRC | 1 | | 1 | | 1 | 1 | 1 | |
| Lesotho | | | | | 1 | 1 | | |
| Malawi | | | 1 | | 1 | 1 | 1 | |
| Mozambique | 1 | 1 | 1 | | 1 | 1 | 1 | |
| Namibia | 1 | | 1 | | 1 | 1 | | |
| South Africa | 2030 | 1 | 1 | 1 | 1 | 1 | 1 | |
| eSwatini | | | 1 | | 1 | 1 | 1 | |
| Tanzania | 1 | | 1 | | 1 | 1 | 1 | 1 |
| Zambia | | | 1 | | 1 | 1 | 1 | 1 |
| Zimbabwe | | | 1 | | 1 | 1 | 1 | |

*Source: IRENA (2013) with the exception that we assume gas is not available to Zambia and that gas is available to South Africa from 2030 following Total's large offshore discovery in 2019.*
*Note: A "1" indicates that a fuel is available to be used by the power sector in the given country. "2030" indicates the year that we assume gas becomes available to the power sector in South Africa.*

In the model, we express fuel prices in real US$2018 per $MWh_{[th]}$, where [th] indicates that the MWh is expressing thermal energy, not electrical energy. We derive a base fuel price for South Africa and include country-specific fuel price differentials, where relevant, to reflect different fuel transportation costs or different cost of sourcing the fuel.

LNG, diesel and HFO prices are assumed to be linked to the price of crude oil. We take the ratio of fuel price to crude oil price from the SAPP Pool Plan (2017), using the ratio of fuel prices to crude oil prices from the SAPP Pool Plan (2017). Diesel is 132% of the price of crude oil and HFO is 90% of the price of crude oil throughout the modelling period, with crude oil and fuel prices expressed in the same units, i.e. US$2018 per $MWh_{[th]}$. LNG prices fall from 112% of crude oil prices in 2017 to 83% of crude oil prices in 2040. We then take the projected crude oil price in real terms from the World Bank's Commodity Markets Outlook April 2019 (WB Group, 2019), and use the ratios described above to project LNG, diesel and HFO prices.

Other fuel prices are taken from the SAPP Pool Plan (2017), with the exception of domestic gas price that we set to equal to US$2018 5.00 per MMBtu. This is higher than the domestic gas price assumed by the SAPP Pool Plan (2017) but in our view better reflects the economic value of gas. The price spread for fuel import countries is taken from IRENA (2013) for gas, HFO, diesel and coal, with the exception of coal imported into Malawi which uses the price spread from the SAPP Pool Plan (2017). IRENA (2013) assumes that imported gas is about US$10 per $MWh_{[th]}$ more expensive than domestic gas. We use this price differential for Zimbabwe, which could potentially import gas from Mozambique in future. IRENA (2013) assumes that countries in the interior pay about US$15/$MWh_{[th]}$ more for diesel and HFO than coastal countries. We apply this differential to Botswana, Lesotho, Malawi, Swaziland, Zambia and Zimbabwe. Finally, IRENA (2013) assumes that imported coal prices are about $5.00/$MWh_{[th]}$ higher than domestic coal prices. We apply this differential to Angola, DRC, Tanzania. Malawi would import coal from Mozambique, and we apply the price differential used by the SAPP Pool Plan (2017) of $2.52/$MWh_{[th]}$.

We also use IRENA (2013) for biomass prices. IRENA (2013) categorises biomass availability in each country as either free (sugarcane waste), moderately available or scarce. Where biomass is freely available (Mozambique, Swaziland, Tanzania, Zambia) we assume a zero price for fuel, where biomass is scarce (Namibia and Lesotho) we assume that it is unavailable and where biomass is moderately available (Angola, Botswana, DRC, Malawi, South Africa and Zimbabwe) we apply IRENA's price of \$1.50/GJ which is \$5.40/$MWh_{[th]}$.

Fuel prices for 2020 and 2030 are shown in **Table 40** and **Table 41**.

**Table 40 Fuel prices, 2020**

| Country | Gas | Gas from LNG | Coal | Uranium | Diesel | HFO | Biomass |
|---|---|---|---|---|---|---|---|
| **DRC** | 27.45 | n/a | 14.37 | n/a | 47.08 | 32.12 | 5.40 |
| **Zambia** | n/a | n/a | 9.37 | n/a | 62.08 | 47.12 | 0.00 |
| **Namibia** | 17.45 | n/a | 9.37 | n/a | 47.08 | 32.12 | n/a |
| **Zimbabwe** | 27.45 | n/a | 9.37 | n/a | 62.08 | 47.12 | 5.40 |
| **Mozambique** | 17.45 | 37.18 | 9.37 | n/a | 47.08 | 32.12 | 0.00 |
| **Botswana** | n/a | n/a | 9.37 | n/a | 62.08 | 47.12 | 5.40 |
| **South Africa** | 17.45 | 37.18 | 9.37 | 5.15 | 47.08 | 32.12 | 5.40 |
| **Lesotho** | n/a | n/a | n/a | n/a | 62.08 | 47.12 | n/a |
| **eSwatini** | n/a | n/a | 9.37 | n/a | 62.08 | 47.12 | 0.00 |
| **Tanzania** | 17.45 | n/a | 14.37 | n/a | 47.08 | 32.12 | 0.00 |
| **Malawi** | n/a | n/a | 11.67 | n/a | 62.08 | 47.12 | 5.40 |
| **Angola** | 17.45 | n/a | 14.37 | n/a | 47.08 | 32.12 | 5.40 |

*Source: SAPP Pool Plan (2017) for the relationship between crude oil prices and LNG, diesel and HFO. World Bank Commodities Market Outlook April 2019 for crude oil price projections (WB Group, 2019). SAPP Pool Plan 2017 for coal and uranium base fuel prices and Malawi coal prices. We assume base gas prices are US\$5.00/MMBtu. IRENA (2013) for biomass prices and for price differentials of importing countries for gas, liquid fuels and coal.*
*Note: All units are in US\$2018/*$MWh_{[thermal]}$.

**Table 41 Fuel prices, 2030**

| Country | Gas | Gas from LNG | Coal | Uranium | Diesel | HFO | Biomass |
|---|---|---|---|---|---|---|---|
| **DRC** | 27.45 | n/a | 14.94 | n/a | 47.53 | 32.42 | 5.40 |
| **Zambia** | n/a | n/a | 9.94 | n/a | 62.53 | 47.42 | 0.00 |
| **Namibia** | 17.45 | n/a | 9.94 | n/a | 47.53 | 32.42 | n/a |
| **Zimbabwe** | 27.45 | n/a | 9.94 | n/a | 62.53 | 47.42 | 5.40 |
| **Mozambique** | 17.45 | 28.03 | 9.94 | n/a | 47.53 | 32.42 | 0.00 |
| **Botswana** | n/a | n/a | 9.94 | n/a | 62.53 | 47.42 | 5.40 |
| **South Africa** | 17.45 | 28.03 | 9.94 | 5.15 | 47.53 | 32.42 | 5.40 |
| **Lesotho** | n/a | n/a | n/a | n/a | 62.53 | 47.42 | n/a |
| **eSwatini** | n/a | n/a | 9.94 | n/a | 62.53 | 47.42 | 0.00 |
| **Tanzania** | 17.45 | n/a | 14.94 | n/a | 47.53 | 32.42 | 0.00 |
| **Malawi** | n/a | n/a | 9.94 | n/a | 62.53 | 47.42 | 5.40 |
| **Angola** | 17.45 | n/a | 14.94 | n/a | 47.53 | 32.42 | 5.40 |

*Source: See above.*
*Note: All units are in US\$2018/*$MWh_{[thermal]}$.

### *Capacity requirement*

We apply a generation capacity requirement in the planning model that reflects the need for a power system to have standing reserves and spinning reserves. The extent to which an individual power plant contributes towards the capacity requirement depends on whether it is expected to be available during the peak demand period. In South Africa, the country in the SAPP region with largest demand, during summer the daily peak is relatively flat across the day with a slight increase in the evening around 20:00 hours while in winter the demand shape is different, with a more pronounced peak earlier in the evening around 19:00 hours (van Deventer, 2014). With this in mind, we use the same power plant type specific percentage contributions to meeting the capacity requirement as listed in **Table 24**. In effect those power plants with a low contribution to meeting the capacity requirement, in particular solar power plants without storage and wind turbines, require back up capacity in the model.

Whether interconnector import capacity is able to contribute towards a country's capacity requirement depends largely on sector policies. As noted, while the SAPP's generation planning criteria includes a long-term objective for each country to have sufficient generation capacity to meet its peak demand, SAPP does allow countries to meet their capacity requirement at any one time through firm contracts to import electricity. As the sector matures and electricity trade expands and trust in the market to deliver electricity to where it is needed most deepens, countries may begin to take into account import capacity in considering how best to meet their capacity requirements. We therefore explore the effects of interconnector capacity contributing towards the capacity requirement.

**Discount rate**

To compare costs that are incurred at different periods in time, we multiply the cost in each year by a discount factor to express all costs as the present value at a common point in time, the beginning of 2018 when looking at the costs of providing access (Chapter 3) and the beginning of 2019 when estimating the effect of trade on costs (Chapter 4). We follow SAPP Pool Plan (2017) and use a 6% real discount rate. A real discount rate of 6% per annum is used, as per the SAPP Pool Plan (2017). In Chapter 4 when additional sensitivities are analysed, we also use a 10% real discount rate.

**Demand within the year**

Chronological hourly demand shape within the year for all countries is derived from South African hourly demand for 2010 (Energy Research, 2010), which is the same hourly demand shape used by IRENA (2013). These data are shifted by one hour (forwards or backwards) for those countries not on the same time zone as South Africa.

We developed a non-linear program in GAMS to adjust the hourly demand shape for each country and each year such that the projected peak demand (MW), and projected annual energy demand (GWh) for each country are met in each year. We use the open source package IPOPT as the non-linear solver (Wächter and Biegler, 2016).

The South African hourly demand in a year is expressed as a percentage of peak demand in the year. We first apply this normalised hourly demand to the projected peak demand (MW) for each country and each year to get the unadjusted hourly demand (MW) for each year for each country. While the peak demand matches our projection, the annual demand will be too high or too low and therefore we adjust the hourly demand.

The demand adjustment model chooses a single scaling parameter for the year and country that minimises the square of the difference between the annual energy of the adjusted South African demand shape and the annual energy in our demand projection, i.e. the demand model chooses the scaling parameter such that the difference is zero. The scaling parameter does not apply to the maximum and minimum demand in a year and applies progressively more strongly to demand that is further from the maximum or minimum and closer to the average demand for the year. In this way we retain the projected peak demand (MW), which is an important driver of generation capacity needs, while adjusting the energy demand (GWh) for the year.

However, one drawback of this approach is that it is likely to overstate the hourly correlation of demand between countries which would tend to understate the benefit of short term trade. A market must be relatively well functioning in order to take advantage of short term trade opportunities. Although the SAPP has a short term trading platform in place, we do not expect that market participants would be able to capture fully the short term trade opportunities. Therefore, we do not view overstating hourly correlation of demand between countries as detrimental to our analysis.

**Representation of time**

All times in the model region are expressed as South African time, which means that demand is offset by one hour in countries whose time zone is one hour ahead or one hour behind South Africa.

The basic unit of time in the optimisation model is an hour. However, not all hours in the model period can be represented individually in the optimisation model due to computational limitations. Rather, we use a sample of hours whereby within each year, model hours are grouped into two seasons of equal duration (wet and dry), two weeks in each season and three 24-hour days in each week (one weekday and two weekend days), i.e. twelve 24-hour days in total. Each model hour is then given a weight according to the number of days represented by the corresponding model day, and the sum of the weights over the twelve model days equals 8,760 (the number of hours in a non-leap year).

Similarly, we do not represent all years over the model period. Rather, the model works with sample years to reduce computational time. We relied on sample years 2018, 2020, 2022, 2024, 2026, 2028, 2030 when looking at the costs of providing access to electricity (Chapter 3). Later on in our research when looking at the benefits of trade and when we allow endogenous decisions regarding interconnector investments (Chapter 4), we include 2019 as a sample year and the year 2018 is used to initiate the model run, with 2019 being the first year for which the model varies the solution according to the demand scenario. This also means that the total costs are summed across the period 2018 to 2030 (or 2018 to 2040 under the delayed SDG target scenario) in Chapter 3 and 2019 to 2030 in Chapter 4 of this thesis.

We weight each model year by the discounted number of years represented by the model year. Thus, the model year 2020, for example, represents two years and has a weight of 1 + 1 / (1 + discount rate), assuming start of year cashflows. In the objective function, the hourly weights are applied to variable costs within a year, and the annual weights are applied to variable costs and to annual costs.  Investment costs are calculated separately, as the sum of the annuitized investment cost where only the annuity for those years up to the end of the modelling horizon is included in the sum.

In summary, the power system is simultaneously optimised over each hour and year for the entire planning horizon with the model having a perfect foresight over the whole planning horizon. Here we refer to hour and year since some variables are annual decisions (new generation commissioning and retirement) while some variables are hourly decisions (generation output, loss of load, lack of capacity, interconnector flow).

# Annex 5: Interconnector transfer capacity

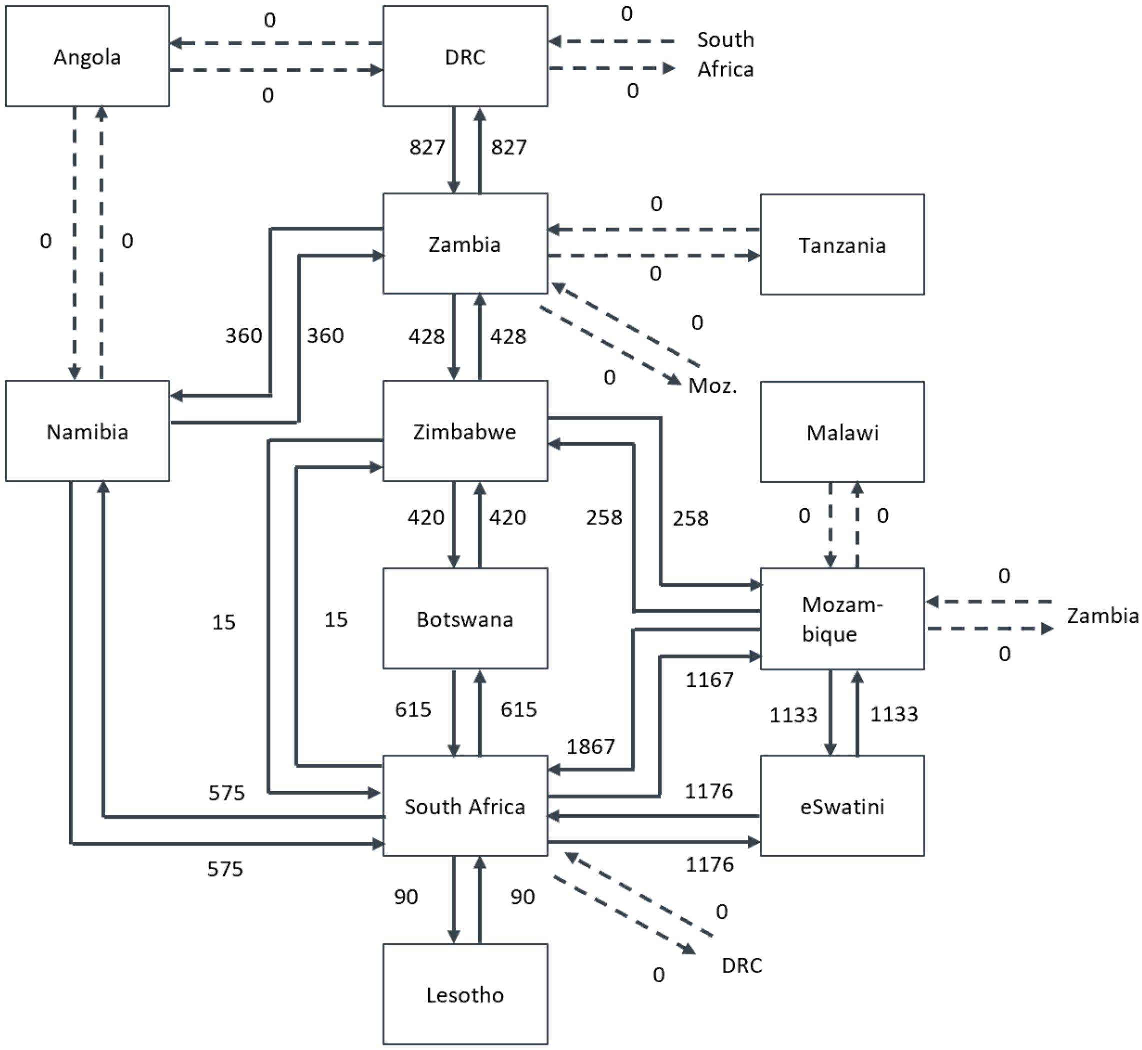
Currently, nine of the twelve countries in the SAPP region are interconnected, with projects to connect Angola, Tanzania and Malawi in development. Of these projects the connection between Tanzania and Zambia appears to be the most advanced, with this interconnection forming part of the larger project to connect Kenya, Tanzania and Zambia (ZTK). In addition, the SAPP Pool Plan (2017) sets out other projects aimed at strengthening existing interconnectors between countries.

We explicitly model transmission losses on interconnectors between countries, using IRENA (2013) as the source. Where IRENA does not provide information about the losses on an interconnector, we use the losses from an interconnector of similar voltage (where known) and length. The losses are applied such that the electricity received by the importing country is reduced according to the % losses relative to the electricity sent by the exporting country.

Our optimisation model starts with existing interconnectors capacity in the region (**Figure 19**). When calculating the costs of providing access (Chapter 3 of this thesis), we did not attempt to optimise the development of future interconnector capacity in the generation simulation model. Rather, the interconnector transfer capacity between countries was an exogenous input into the model. That is, the interconnector capacity was set to equal to SAPP data on transfer capacity in the case of currently interconnected countries and on the basis of reports about the development of new interconnectors in the case of Angola, Malawi and Tanzania. In other words, with the exception of the new interconnectors to the three as yet unconnected SAPP countries, we hold interconnector transfer capacity constant throughout the modelling period.

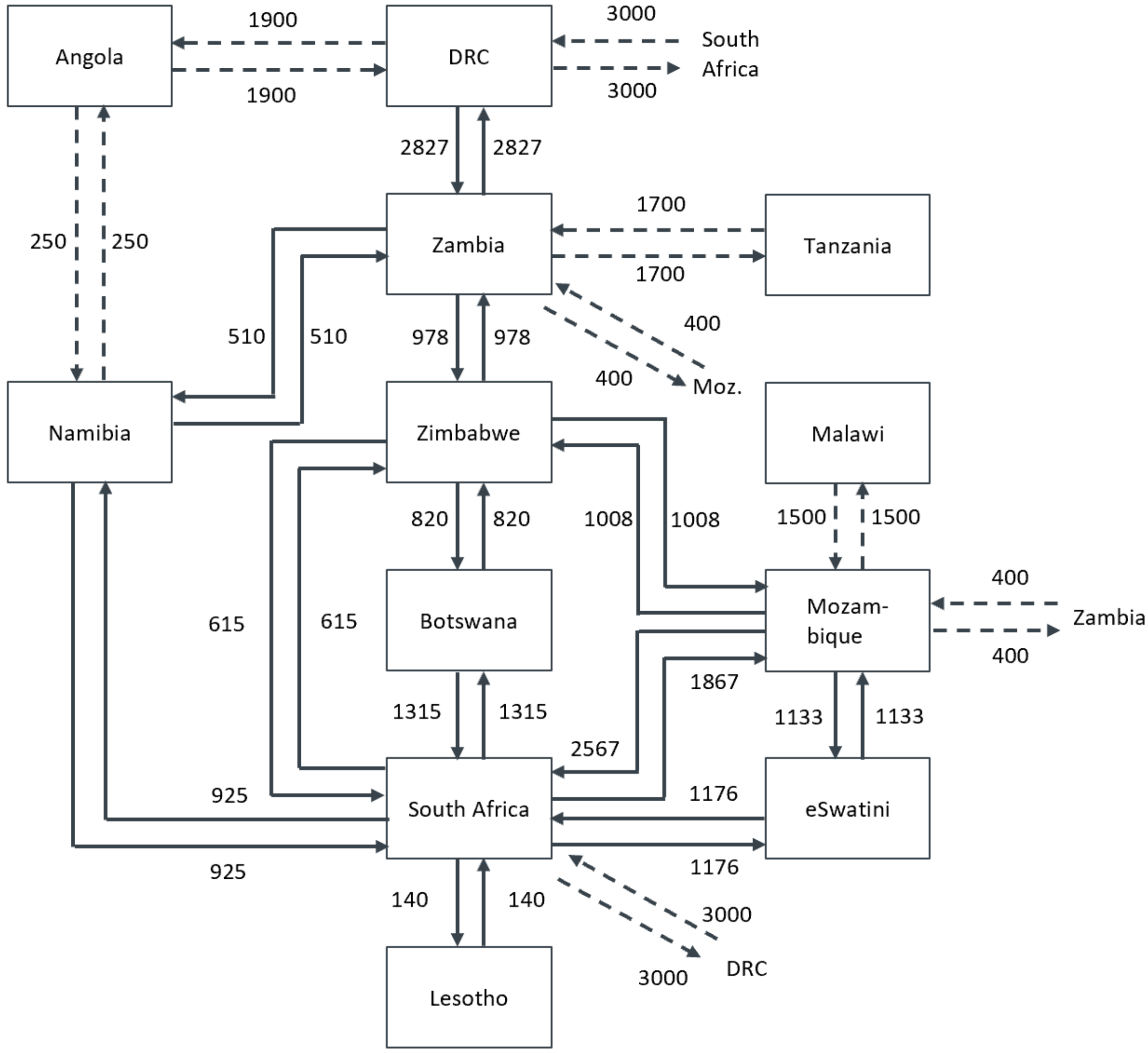
However, as our research developed, when looking at the effects of trade we also optimise the development of future interconnector capacity in the generation simulation model. Here our optimisation model also starts with existing interconnectors, but develops new interconnector capacity between countries where economically efficient to do so under the full trade scenario. Each interconnector project is specified in the model by the two countries it connects, transfer capacity, investment cost, losses and its earliest commissioning year. **Figure 20** shows transfer capacity with all possible interconnector projects currently considered for development, which were all considered in our analysis.

**Figure 19: SAPP region with current interconnector transfer capacities (MW)**




*Source: SAPP (2020), JICA (2018b), World Bank (2018b).*

**Figure 20: SAPP region with possible future interconnector transfer capacity (MW)**




*Source: SAPP (2020), JICA (2018b), World Bank (2018b), SAPP Pool Plan (2017).*
*Note: Transfer capacity is based on transmission interconnector projects under development. It is likely that not all projects are completed, and it is also possible that new projects are identified.*

Current interconnector capacity between countries is based on SAPP information published on its website on transfer capacity. New interconnector projects are based on the SAPP Pool Plan (2017), with some earliest commissioning dates delayed to reflect project development potentially beginning in 2019, and with adjustment of costs to express them in terms of 2018 US$ and per kW of transfer capacity (**Table 42**). Losses are sourced from IRENA (2013) where available for existing interconnectors. Where information about losses was not available, we have assumed losses for broadly similar projects in terms of length and voltage.

Some projects are developed in phases with the first phase having relatively low transfer capacity compared to subsequent phases because of the need to provide reserves in case of line failure. This means that subsequent phases are cheaper than the first phase on a per MW basis. To avoid the model building phase 2 of a project before phase 1, in these cases we express both phases in the model as a single project with a single average investment cost.

**Table 42: Interconnector projects**

| Country 1 | Country 2 | Transfer capacity (MW) | Earliest commissioning year | Investment cost (US$2018/kW) | Losses (%) |
|---|---|---|---|---|---|
| Zambia | Tanzania | 200 | 2025 | 5,304 | 10% |
| Zambia | Zimbabwe | 250 | 2023 | 277 | 1% |
| Zimbabwe | South Africa | 300 | 2023 | 286 | 3% |
| Angola | DRC | 1,100 | 2023 | 372 | 3% |
| Angola | DRC | 800 | 2025 | 274 | 3% |
| Angola | Namibia | 250 | 2023 | 457 | 5% |
| Namibia | Zambia | 150 | 2023 | 530 | 5% |
| Namibia | South Africa | 350 | 2023 | 446 | 5% |
| DRC | Zambia | 2,000 | 2026 | 770 | 10% |
| DRC | South Africa | 3,000 | 2026 | 901 | 13% |
| Zambia | Tanzania | 1,500 | 2027 | 774 | 8% |
| Zambia | Zimbabwe | 300 | 2023 | 313 | 1% |
| Botswana | Zimbabwe | 400 | 2023 | 71 | 3% |
| Botswana | South Africa | 700 | 2023 | 118 | 2% |
| Zimbabwe | South Africa | 300 | 2023 | 381 | 3% |
| Mozambique | Zambia | 400 | 2023 | 301 | 3% |
| Mozambique | Zimbabwe | 200 | 2023 | 311 | 3% |
| Mozambique | Zimbabwe | 400 | 2025 | 247 | 3% |
| Malawi | Mozambique | 1,000 | 2023 | 599 | 3% |
| Malawi | Mozambique | 500 | 2025 | 163 | 3% |
| Mozambique | Zimbabwe | 150 | 2023 | 422 | 3% |
| Mozambique | South Africa | 700 | 2023 | 125 | 3% |
| Lesotho | South Africa | 50 | 2023 | 816 | 1% |

*Source: SAPP Pool Plan (2017) with costs adjusted to 2018 and expressed per kW, IRENA (2013), JICA (2018b), Club of Mozambique (2019), World Bank (2018b).*

We note that, interconnector decisions (build and flow decisions) affect the objective function directly only though interconnector capex and indirectly through several mechanisms, including energy losses as power flows through the interconnector (increasing generation operating costs), by interconnector flows allowing cheap generation output to displace expensive generation and possibly to displace loss of load output, and through interconnector import capacity helping to meet the capacity requirement for the importing country (potentially reducing generation capex).

# Annex 6: Current and future level of on-grid demand

## Table 43: Current level of on-grid consumption, sent-out and peak demand (2018)

| | Invoiced consumption, national territory | Non-technical losses | Total customer demand | Technical losses | Sent-out demand | Peak demand |
|---|---|---|---|---|---|---|
| **Unit** | *GWh* | *GWh* | *GWh* | *GWh* | *GWh* | *MW* |
| Angola | 8,884 | 1,111 | 9,995 | 1,111 | 11,105 | 1,950 |
| Botswana | 3,209 | 185 | 3,394 | 377 | 3,775 | 575 |
| DRC | 7,697 | 3,476 | 11,173 | 1,241 | 12,415 | 2,024 |
| Lesotho | 778 | 26 | 804 | 89 | 893 | 183 |
| Malawi | 2,560 | 88 | 2,648 | 294 | 2,942 | 529 |
| Mozambique | 12,993 | 1,067 | 14,061 | 1,114 | 15,164 | 2,157 |
| Namibia | 4,171 | 70 | 4,241 | 471 | 4,712 | 723 |
| South Africa | 218,940 | 2,460 | 221,400 | 24,600 | 246,000 | 37,443 |
| Eswatini | 1,116 | 38 | 1,154 | 157 | 1,312 | 263 |
| Tanzania | 6,691 | 480 | 7,171 | 797 | 7,968 | 1,297 |
| Zambia | 12,546 | 1,058 | 13,605 | 1,512 | 15,116 | 2,512 |
| Zimbabwe | 8,664 | 1,006 | 9,670 | 1,074 | 10,744 | 2,095 |
| **Total** | **288,250** | **11,064** | **299,314** | **32,837** | **332,141** | |
| **Total, excluding SA** | **69,310** | **8,604** | **77,914** | **8,237** | **86,141** | |
| *Mozambique, excl. Mozal* | *5,337* | *1,067* | *6,404* | *711* | *7,105* | |
| *Mozal* | *7,656* | *-* | *7,656* | *403* | *8,059* | *1,000* |

*Source: Authors based on IEA (2019a), SAPP Pool Plan (2017), JICA (2018a), JICA (2018b), Norconsult et al. (2017), SA IRP (2019), SAPP (2018), IEA (2019c) and utilities annual reports available for Botswana (BPC, 2018); Lesotho (LEC, 2018), Namibia (NamPower, 2018), South Africa (Eskom, 2019), eSwatini (EEC, 2018), Tanzania (TANESCO, 2018); Zambia (ZESCO, 2017) and Zimbabwe (ZETDC, 2018).*

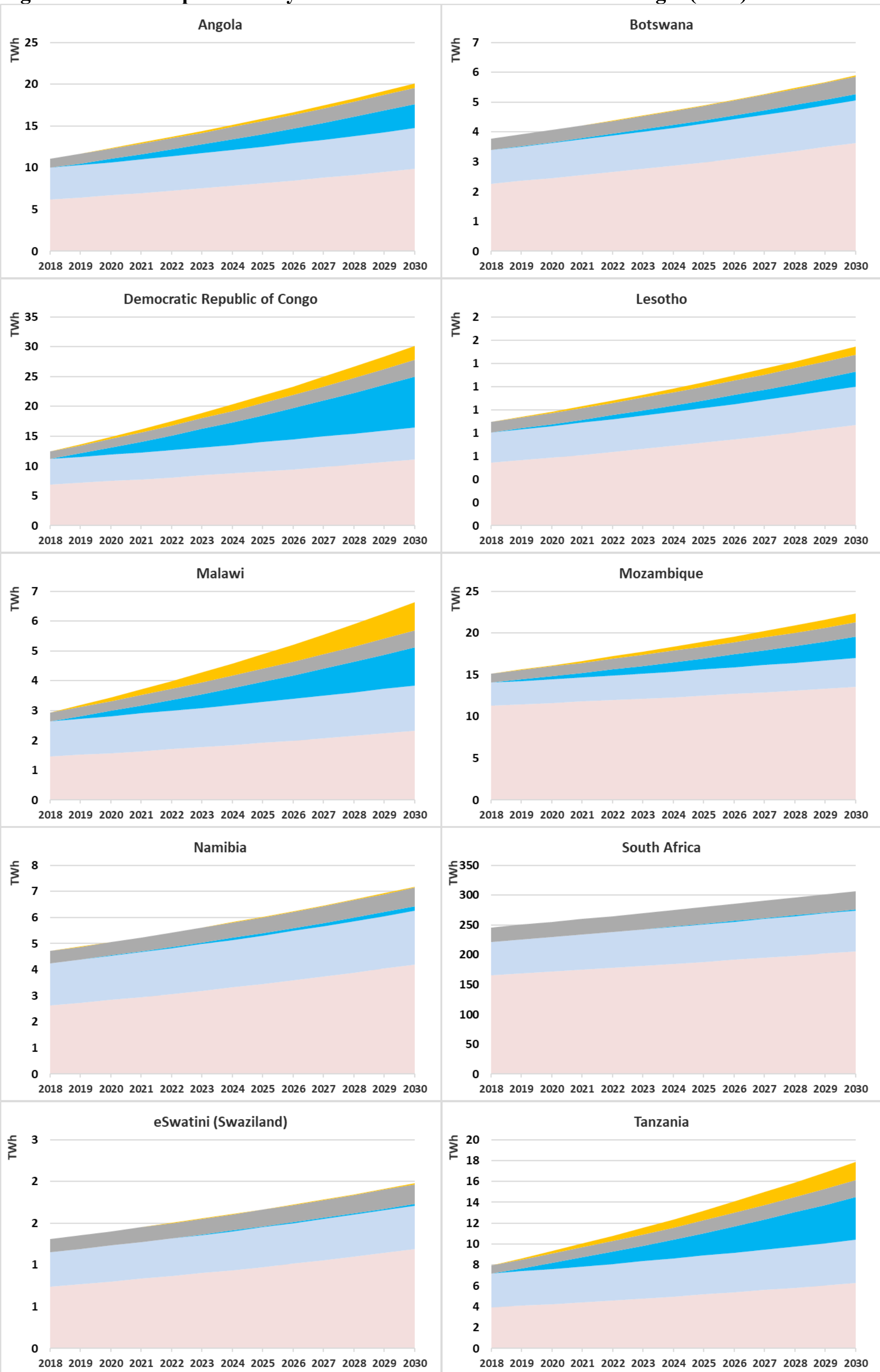
*Note: 'Sent-out' and 'Peak demand' represent the domestic demand to be met at the point of injection to the transmission network.*

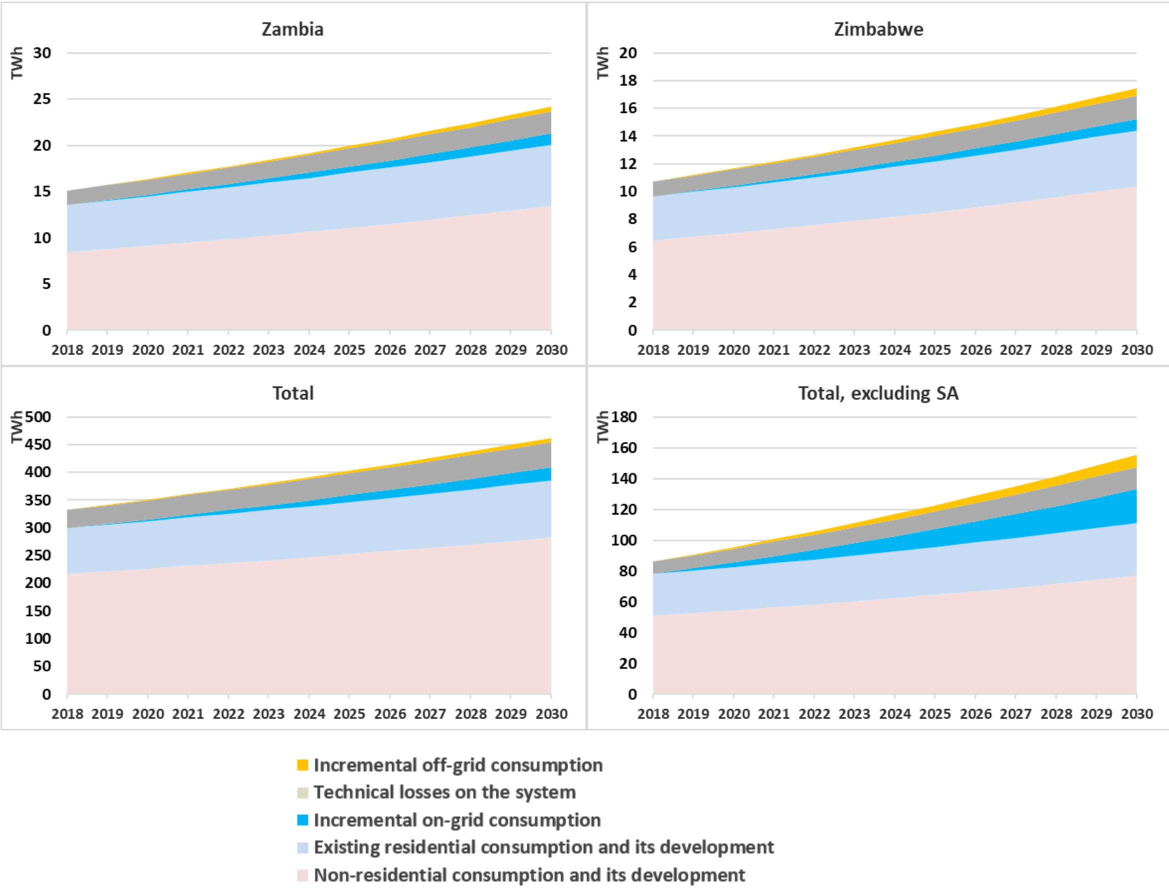
## Table 44: Future level of on-grid consumption under different scenarios (2030)

| Scenario | No new household connections | Current rate of progress | Universal access target | No new household connections | Current rate of progress | Universal access target |
|---|---|---|---|---|---|---|
| ***Unit*** | *GWh* | *GWh* | *GWh* | *CAGR (%)* | *CAGR (%)* | *CAGR (%)* |
| Angola | 14,732 | 16,043 | 17,610 | 3.3% | 4.0% | 4.8% |
| Botswana | 5,059 | 5,161 | 5,274 | 3.4% | 3.6% | 3.7% |
| DRC | 16,470 | 16,632 | 25,012 | 3.3% | 3.4% | 6.9% |
| Lesotho | 1,200 | 1,280 | 1,326 | 3.4% | 4.0% | 4.3% |
| Malawi | 3,843 | 4,018 | 5,120 | 3.2% | 3.5% | 5.6% |
| Mozambique | 17,003 | 17,484 | 19,554 | 1.6% | 1.8% | 2.8% |
| Namibia | 6,251 | 6,319 | 6,428 | 3.3% | 3.4% | 3.5% |
| South Africa | 274,253 | 276,319 | 276,319 | 1.8% | 1.9% | 1.9% |
| Eswatini | 1,711 | 1,731 | 1,731 | 3.3% | 3.4% | 3.4% |
| Tanzania | 10,403 | 11,921 | 14,499 | 3.1% | 4.3% | 6.0% |
| Zambia | 20,053 | 20,473 | 21,312 | 3.3% | 3.5% | 3.8% |
| Zimbabwe | 14,419 | 14,458 | 15,224 | 3.4% | 3.4% | 3.9% |
| **Total** | **385,398** | **391,839** | **409,409** | **2.1%** | **2.3%** | **2.6%** |
| **Total, excluding SA** | **111,146** | **115,520** | **133,090** | **3.0%** | **3.3%** | **4.6%** |
| *Mozambique, excl. Mozal* | *9,348* | *9,919* | *11,898* | *3.2%* | *3.6%* | *5.3%* |
| *Mozal* | *7,656* | *7,656* | *7,656* | *0.0%* | *0.0%* | *0%* |
| **Incremental on-grid cons.** | **n/a** | **6,441** | **15,877** | | | |

*Source: Authors based on IEA (2019a), IEA/OECD (2017) and WDI (2020).*

**Figure 21: Consumption and system load under a universal access target (2030)**






*Source: Authors based on IEA (2019a), IEA (2018), IEA (2017), IEA (2015), the World Bank's World Development Indicators (SP.POP.TOTL), SAPP Pool Plan (2017), JICA (2018a), JICA (2018b), Norconsult et al. (2017), South African Integrated Resource Plan (2019), IEA (2019b) and utilities annual reports.*

*Note: For off-grid, only incremental off-grid consumption is shown. The y-axis scale varies by chart to reflect the size of the various power systems.*

# Annex 7: Core code developed in GAMS

Below is the core code developed for the GAMS model, including endogenous decisions about new interconnectors.

**Variables**

| | |
|---|---|
| vTotalCost | Objective function value |

**Positive Variables**

| | |
|---|---|
| vGenSetOut(sYears, sSeasons, sDays, sHours, sGenSets) | Hourly output from each gen in MWh or MW |
| vLoL(sYears, sSeasons, sDays, sHours, sRegions) | Hourly loss of load in each region in MWh or MW |
| vLoC(sYears, sRegions) | Annual lack of capacity in each region in MW |
| vNewCap(sYears, sGenSets) | New gen capacity built in a year in MW |
| vInstalledCap(sYears, sGenSets) | Cumulative installed capacity of each gen in MW |
| vTxNewCap(sYears, sTx) | New tx capacity built in a year in MW |
| vTxInstalledCap(sYears, sTx) | Cumulative installed capacity of each tx line in MW |
| vLineFlow(sYears, sSeasons, sDays, sHours, sTx) | Hourly flow on each tx line in MWh or MW |
| vRetCap(sYears, sGenSets) | Gen capacity retired in each year in MW |
| vGenVarCost(sYears, sSeasons, sDays, sHours, sGenSets) | Variable costs of gen in USD |
| vVoLLCost(sYears, sSeasons, sDays, sHours, sRegions) | Costs of unserved energy in USD |
| vVoLCCost(sYears, sRegions) | Costs of unmet capacity requirement in USD |
| vGenInvCost(sYears, sGenSets) | Gen investment costs in USD |
| vGenFOMCost(sYears, sGenSets) | Gen fixed O&M cost in USD |
| vTxInvCost(sYears, sTx) | Tx investment cost in USD |

** Integer variables by default have a lower bound of 0*

**Integer variables**

| | |
|---|---|
| vIntBuild(sYears, sGenSets) | Integer multiplier on unit size for new gen |
| vIntRet(sYears, sGenSets) | Integer multiplier on unit size for retirement of existing gen |
| vTxIntBuild(sYears, sTx) | Integer multiplier on line size for new tx lines |

**Equations**

| | |
|---|---|
| Objective2 | Objective function present value total costs at start of base year in USD |
| eGenVarCost | Variable costs of gen expressed at the start of the model year in USD |
| eVoLLCost | Costs of unserved energy at the start of the model year in USD |
| eVoLCCost | Costs of unmet capacity requirement at the start of model year in USD |
| eGenInvCost | Gen investment costs expressed at start of the investment year in USD |
| eTxInvCost | Tx investment costs expressed at start of the investment year in USD |
| eGenFOMCost | Gen fixed O&M cost at the start of the model year in USD |
| eDemandBalance | Demand supply balance for each region in each hour in MWh |
| eMaxCap | Maximum installed capacity for a gen in MW |
| eInitCap1 | Fixed new gen capacity in year 1 equals capacity of committed gen commissioned in year 1 in MW |
| eInitCap2 | Fixed installed gen capacity in year 1 equals capacity of existing gen plus committed new gen in year 1 in MW |
| eNewCapExisting | Fixed new gen capacity after year 1 equals capacity of committed gen commissioned in that year in MW |
| eInstCapExisting | Fixed installed gen capacity after year 1 equals installed capacity y-1 plus additions less retirements in MW |
| eIntRetExisting | Fixed gen capacity retirement before forced retirement year must be an integer number of units in MW |
| eInstCapCandY1 | Candidate installed gen capacity in year 1 equals capacity of candidate gen commissioned in y1 in MW |
| eInstCapCand | Candidate installed gen capacity after year 1 equals installed capacity y-1 plus additions in MW |
| eIntNewCand | Candidate new gen capacity must be an integer number of units if |

| | |
|---|---|
| | integer flag set in MW |
| eTxMaxCap | Maximum installed capacity for a transmission line in MW |
| eTxInitCap1 | Fixed new tx capacity in year 1 equals capacity of committed tx commissioned in year 1 in MW |
| eTxInitCap2 | Fixed installed tx capacity in year 1 equals capacity of existing tx plus committed new tx in year 1 in MW |
| eTxNewCapExisting | Fixed new tx capacity after year 1 equals capacity of committed tx commissioned in that year in MW |
| eTxInstCapExisting | Fixed installed tx capacity after year 1 equals installed capacity y-1 plus additions in MW |
| eTxInstCapCandY1 | Candidate installed tx capacity in year 1 equals capacity of candidate tx commissioned in year 1 in MW |
| eTxInstCapCand | Candidate installed tx capacity after year 1 equals installed capacity y-1 plus additions in MW |
| eTxIntNewCand | Candidate new tx capacity must be an integer number of lines in MW |
| eCapReq | Firm capacity in a region is greater than the regional firm capacity requirement in MW |
| eMaxFlowHour | Max injection into a tx line in MW |
| eMaxGenHour | Max gross gen output less than installed capacity adjusted for availability in MW |
| eMaxGenAnn | Max gross gen output over the year in MWh |
| eMinGenAnn | Min gross gen output over the year in MWh |
| eMinGenHour | Min gross output in an hour in MWh or MW |
| eMaxFuelBurn | Max fuel consumption over the year in a region in MWh[th] |
| eTxPairs | Forward and reverse candidate tx capacity must be commissioned in same year. Note that only a sample of these equations is shown here. |
| eTxPairs1 | |
| eTxPairs2 | |
| … | |
| eTxPairs23; | |

```
* Objective function discounts start of year costs to start of base year
Objective2..
  vTotalCost              =E=  SUM((sYearsMod, sSeasons, sDays, sHours, sGenSets), vGenVarCost(sYearsMod,
                          sSeasons, sDays, sHours, sGenSets) * pDiscFactor(sYearsMod))
                                    +  SUM((sYearsMod, sSeasons, sDays, sHours, sRegions),
                          vVoLLCost(sYearsMod, sSeasons, sDays, sHours, sRegions) * pDiscFactor(sYearsMod))
                                    +  SUM((sYearsMod, sRegions), vVoLCCost(sYearsMod,
                          sRegions) * pDiscFactor(sYearsMod))
                                    +  SUM((sYearsMod, sGenSets), vGenInvCost(sYearsMod,
                          sGenSets) * pDiscFactor(sYearsMod))
                                    +  SUM((sYearsMod, sTx), vTxInvCost(sYearsMod, sTx) *
                          pDiscFactor(sYearsMod))
                                    +  SUM((sYearsMod, sGenSets), vGenFOMCost(sYearsMod,
                          sGenSets) * pDiscFactor(sYearsMod));

* Variable costs equal SRMC x output with annual and hourly weights since snapshot years and hours are modelled
* Annual weights use start of year cashflows discounted to the start of the snapshot year
eGenVarCost(sYearsMod, sSeasons, sDays, sHours, sGenSets)..
vGenVarCost(sYearsMod, sSeasons, sDays, sHours, sGenSets) =E=  pGenMC(sYearsMod, sSeasons, sDays, sHours,
sGensets) * vGenSetOut(sYearsMod, sSeasons, sDays, sHours, sGenSets) * pAnnWeight(sYearsMod) *
pHlyWeights(sSeasons, sDays, sHours);

* Costs of energy not served equal loss of load x value of lost load with annual and hourly weights
eVoLLCost(sYearsMod, sSeasons, sDays, sHours, sRegions)..
 vVoLLCost(sYearsMod, sSeasons, sDays, sHours, sRegions)  =E=  vLoL(sYearsMod, sSeasons, sDays, sHours,
sRegions) * pVoLL * pAnnWeight(sYearsMod) * pHlyWeights(sSeasons, sDays, sHours);

* Cost of capacity requirement not met equals lack of capacity x cost of capacity shortage with annual weights
eVoLCCost(sYearsMod, sRegions)..
 vVoLCCost(sYearsMod, sRegions)        =E=  vLoC(sYearsMod, sRegions) * pVoLC * pAnnWeight(sYearsMod);
```

```
* Gen investment cost equals new gen capex annuity summed over the shorter of the gen economic life and model horizon
* Capex annuity is a start of year annuity
* A gen could run beyond its economic life or forced retirement year because of snapshot years
eGenInvCost(sYearsMod, sGenSets)..
 vGenInvCost(sYearsMod, sGenSets)        =E=   vNewCap(sYearsMod, sGenSets) * pGenAnnuity(sGenSets) * ((1-1/(1+pDRate)**min(pModelEnd - pModelYears(sYearsMod) + 1, pGenEconLife(sGenSets))) / pDRate) * (1 + pDRate);

* Tx investment cost equals the new tx capex annuity summed over the shorter of the tx economic life and model horizon
eTxInvCost(sYearsMod, sTx)..
 vTxInvCost(sYearsMod, sTx)              =E=   vTxNewCap(sYearsMod, sTx) * pTxAnnuity(sTx) * ((1-1/(1+pDRate)**min(pModelEnd - pModelYears(sYearsMod) + 1, pTxEconLife(sTx))) / pDRate) * (1 + pDRate);

* Fixed operations and maintenance costs are applied to gen installed capacity with annual weights
eGenFOMCost(sYearsMod, sGenSets)..
 vGenFOMCost(sYearsMod, sGenSets)    =E=   pFOM(sGenSets, sYearsMod) * vInstalledCap(sYearsMod, sGenSets) * pAnnWeight(sYearsMod);

* Energy balance constraint
eDemandBalance(sYearsMod, sSeasons, sDays, sHours, sRegions)..
 pDemandHour(sYearsMod, sSeasons, sDays, sHours, sRegions) =E=  SUM((sGenSets)$(pGenData(sGenSets,"Region")=pRegionNum(sRegions)), vGenSetOut(sYearsMod, sSeasons, sDays, sHours, sGenSets)*(1-pGenOwnCons(sGenSets)))
                         +   vLoL(sYearsMod, sSeasons, sDays, sHours, sRegions)
                         +   SUM((sTx)$(pTxRegion(sTx, sRegions)=-1), vLineFlow(sYearsMod, sSeasons, sDays, sHours, sTx)*(1 - pTxLoss(sTx)))
                         -   SUM((sTx)$(pTxRegion(sTx, sRegions)=1), vLineFlow(sYearsMod, sSeasons, sDays, sHours, sTx));

* Gen installed capacity equals 0 before commissioning and after specified retirement
vInstalledCap.fx(sYearsMod, sGenSets)$(pGenDecomm(sGenSets) AND (pGenDecomm(sGenSets)-sYearsMod.val) < 0) = 0;
vInstalledCap.fx(sYearsMod, sGenSets)$(pGenComm(sGenSets) > sYearsMod.val) = 0;

* Cap on gen installed capacity
eMaxCap(sYearsMod, sGenSets)..
 vInstalledCap(sYearsMod, sGenSets)      =L=   pGenMaxCap(sGenSets);

******Existing and committed genset capacity constraints******
* Temporarily turn off requirement that ord() can only apply to a one-dimensional static ordered set
$OffOrder

* In year 1 new committed genset capacity equals capacity commissioned in year 1 where vNewCap allows for capex
eInitCap1(sYearsMod, sFixedGen)$(ORD(sYearsMod)=1)..
 vNewCap(sYearsMod, sFixedGen)           =E=   pGenMaxCap(sFixedGen)$(pGenComm(sFixedGen) = sYearsMod.val);

* In year 1 installed existing or committed gen capacity equals capacity commissioned before year 1 (no capex) and built in year 1
eInitCap2(sYearsMod, sFixedGen)$(ORD(sYearsMod)=1)..
 vInstalledCap(sYearsMod, sFixedGen)     =E=   pGenMaxCap(sFixedGen)$(pGenComm(sFixedGen) < sYearsMod.val) + vNewCap(sYearsMod, sFixedGen);

* After year 1 new committed genset capacity equals capacity commissioned in that year where vNewCap allows for capex
eNewCapExisting(sYearsMod, sFixedGen)$(ORD(sYearsMod)>1)..
 vNewCap(sYearsMod, sFixedGen)           =E=   pGenMaxCap(sFixedGen)$(pGenSnapComm(sFixedGen) = sYearsMod.val);

* After year 1 installed existing or committed genset capacity equals installed capacity + new build - retirement
eInstCapExisting(sYearsMod, sFixedGen)$(ORD(sYearsMod)>1)..
 vInstalledCap(sYearsMod, sFixedGen)     =E=   vInstalledCap(sYearsMod-1, sFixedGen) + vNewCap(sYearsMod, sFixedGen) - vRetCap(sYearsMod-1, sFixedGen);

$OnOrder
```

```
******End of existing and committed gen capacity constraints******

* Installed tx capacity equals zero before commissioning and tx never retires
vTxInstalledCap.fx(sYearsMod, sTx)$(pTxCommYear(sTx) > sYearsMod.val) = 0;

* Cap on tx installed capacity
eTxMaxCap(sYearsMod, sTx)..
 vTxInstalledCap(sYearsMod, sTx)         =L=   pTxCapDef(sTx);

******Fixed transmission capacity constraints******
* Temporarily turn off requirement that ord() can only apply to a one-dimensional static ordered set
$OffOrder

* In year 1 new fixed tx capacity built equals capacity commissioned in year 1 where vTxNewCap allows for capex
eTxInitCap1(sYearsMod, sFixedTx)$(ORD(sYearsMod)=1)..
 vTxNewCap(sYearsMod, sFixedTx)          =E=   pTxCapDef(sFixedTx)$(pTxCommYear(sFixedTx) =
sYearsMod.val);

* In year 1 installed fixed tx capacity equals capacity commissioned before year 1 (no capex) and built in year 1
eTxInitCap2(sYearsMod, sFixedTx)$(ORD(sYearsMod)=1)..
 vTxInstalledCap(sYearsMod, sFixedTx)    =E=   pTxCapDef(sFixedTx)$(pTxCommYear(sFixedTx) <
sYearsMod.val) + vTxNewCap(sYearsMod, sFixedTx);

* After year 1 new fixed tx capacity equals capacity commissioned in that year where vTxNewCap allows for capex
* This equation could be combined with the following one.
eTxNewCapExisting(sYearsMod, sFixedTx)$(ORD(sYearsMod)>1)..
 vTxNewCap(sYearsMod, sFixedTx)          =E=   pTxCapDef(sFixedTx)$(pTxSnapComm(sFixedTx) =
sYearsMod.val);

* After year 1 installed fixed tx capacity equals installed capacity + new build only since there is no tx retirement
eTxInstCapExisting(sYearsMod, sFixedTx)$(ORD(sYearsMod)>1)..
 vTxInstalledCap(sYearsMod, sFixedTx)    =E=   vTxInstalledCap(sYearsMod-1, sFixedTx) +
vTxNewCap(sYearsMod, sFixedTx);

$OnOrder
******End of fixed transmission capacity constraints******

* Retirement of fixed gen must be an integer number of units if the integer flag is set
eIntRetExisting(sYearsMod, sFixedGen)$((pIntegerInv(sFixedGen)=1) AND ((sYearsMod.val <
pGenSnapDecomm(sFixedGen)) OR NOT(pGenSnapDecomm(sFixedGen))))..
 vRetCap(sYearsMod, sFixedGen)           =E=   pUnitSize(sFixedGen) * vIntRet(sYearsMod, sFixedGen);

******Candidate gen capacity constraints******
$OffOrder

* In year 1 installed capacity of candidate gen equals the capacity built in year 1
eInstCapCandY1(sYearsMod, sNewGen)$(ORD(sYearsMod)=1)..
 vInstalledCap(sYearsMod, sNewGen)       =E=   vNewCap(sYearsMod, sNewGen);

* After year 1 installed capacity of candidate gen equals installed capacity + new build since no candidate gen
retirement
eInstCapCand(sYearsMod, sNewGen)$(ORD(sYearsMod)>1)..
 vInstalledCap(sYearsMod, sNewGen)       =E=   vInstalledCap(sYearsMod-1, sNewGen) + vNewCap(sYearsMod,
sNewGen);

$OnOrder

* New capacity of candidate gen must be an integer number of units if the integer flag is set
eIntNewCand(sYearsMod, sNewGen)$(pIntegerInv(sNewGen)=1)..
 vNewCap(sYearsMod, sNewGen)             =E=   pUnitSize(sNewGen) * vIntBuild(sYearsMod, sNewGen);
******End of candidate gen capacity constraints******

******Candidate tx capacity constraints******
$OffOrder

* In year 1 installed capacity of candidate tx equals the capacity built in year 1
eTxInstCapCandY1(sYearsMod, sNewTx)$(ORD(sYearsMod)=1)..
```

```
 vTxInstalledCap(sYearsMod, sNewTx)      =E=   vTxNewCap(sYearsMod, sNewTx);

* After year 1 installed capacity of candidate tx equals installed capacity + new build only since there is no
retirement of tx
eTxInstCapCand(sYearsMod, sNewTx)$(ORD(sYearsMod)>1)..
 vTxInstalledCap(sYearsMod, sNewTx)      =E=   vTxInstalledCap(sYearsMod-1, sNewTx) +
vTxNewCap(sYearsMod, sNewTx);

$OnOrder

* New capacity of candidate tx must be an integer number of tx lines
eTxIntNewCand(sYearsMod, sNewTx)..
 vTxNewCap(sYearsMod, sNewTx)           =E=   pTxCapDef(sNewTx) * vTxIntBuild(sYearsMod, sNewTx);

* Forward and reverse directions of candidate tx must be installed at the same time. Elegant approaches do not
work. Note that only a sample of these equations is shown here.
eTxPairs(sYearsMod, sTx)..
 vTxIntBuild(sYearsMod, "T39")          =E=   vTxIntBuild(sYearsMod, "T40");
eTxPairs1(sYearsMod, sTx)..
 vTxIntBuild(sYearsMod, "T41")          =E=   vTxIntBuild(sYearsMod, "T42");
eTxPairs2(sYearsMod, sTx)..
 vTxIntBuild(sYearsMod, "T43")          =E=   vTxIntBuild(sYearsMod, "T44");
...
eTxPairs23(sYearsMod, sTx)..
 vTxIntBuild(sYearsMod, "T85")          =E=   vTxIntBuild(sYearsMod, "T86");
******End of candidate tx capacity constraints******

* Capacity balance constraint
eCapReq(sYearsMod, sSeasons, sDays, sHours, sRegions)$(pUseCapReq = 1)..
 (1 + pGenCapReq) * pDemandHour(sYearsMod, sSeasons, sDays, sHours, sRegions) =L= SUM(sGenSets$
(pGenData(sGenSets,"Region")=pRegionNum(sRegions)), vInstalledCap(sYearsMod, sGenSets) *
pGenCapCredit(sGenSets)) + SUM((sTx)$(pTxRegion(sTx, sRegions)=-1), vTxInstalledCap(sYearsMod, sTx)
                              * (1 - pTxLoss(sTx)) * pICCapCredit) + vLoC(sYearsMod, sRegions);

* Max flow injected into tx line is installed capacity assuming 100 percent availability
eMaxFlowHour(sYearsMod, sSeasons, sDays, sHours, sTx)..
 vLineFlow(sYearsMod, sSeasons, sDays, sHours, sTx)         =L=   vTxInstalledCap(sYearsMod, sTx);

* Max gen output is installed capacity adjusted for availability
eMaxGenHour(sYearsMod, sSeasons, sDays, sHours, sGenSets) ..
  vGenSetOut(sYearsMod, sSeasons, sDays, sHours, sGenSets)    =L=   vInstalledCap(sYearsMod, sGenSets) *
pGenAvailFinal(sYearsMod, sSeasons, sDays, sHours, sGensets);

* Max annual gen output
eMaxGenAnn(sGenSets, sYearsMod)$(pGenAnnMax(sGenSets, sYearsMod)>0) ..
 SUM((sSeasons, sDays, sHours),(vGenSetOut(sYearsMod, sSeasons, sDays, sHours, sGenSets) *
pHlyWeights(sSeasons, sDays, sHours))) =L= pGenAnnMax(sGenSets, sYearsMod);

* Min annual gen output which is only applied to gen that exist in a year
eMinGenAnn(sGenSets, sYearsMod)$((pGenAnnMin(sGenSets, sYearsMod)>0) AND (pGenComm(sGenSets) <=
sYearsMod.val) AND (pGenDecomm(sGenSets) = 0 OR (pGenDecomm(sGenSets) >= sYearsMod.val)))..
 SUM((sSeasons, sDays, sHours),(vGenSetOut(sYearsMod, sSeasons, sDays, sHours, sGenSets) *
pHlyWeights(sSeasons, sDays, sHours))) =G= pGenAnnMin(sGenSets, sYearsMod);

* Min hourly gen output which is only applied to gen that exist in a year
eMinGenHour(sYearsMod, sSeasons, sDays, sHours, sGenSets)$((pGenHrlyMin(sGenSets, sYearsMod)>0) AND
pGenAvailFinal(sYearsMod, sSeasons, sDays, sHours, sGenSets) AND (pGenComm(sGenSets) <= sYearsMod.val)
AND (pGenDecomm(sGenSets) = 0 OR (pGenDecomm(sGenSets) >= sYearsMod.val))) ..
 vGenSetOut(sYearsMod, sSeasons, sDays, sHours, sGenSets)    =G=   pGenHrlyMin(sGenSets, sYearsMod);

* Max fuel consumption equals zero in countries where that fuel is not available
pMaxFuelBurn(sRegions, sYearsMod, sFuels)$(NOT(pFuelAvail(sRegions, sFuels))) = 0.0005;

* Max fuel burn in a year in a country in MWh[th]
eMaxFuelBurn(sRegions, sYearsMod, sFuels)$(pMaxFuelBurn(sRegions, sYearsMod, sFuels) > 0) ..
 pMaxFuelBurn(sRegions, sYearsMod, sFuels)  =G=   SUM((sSeasons, sDays, sHours, sGenSets)$
(pGenData(sGenSets,"Region")=pRegionNum(sRegions) AND pGenData(sGenSets,
```

"FuelType")=pFuelNum(sFuels)), vGenSetOut(sYearsMod, sSeasons, sDays, sHours, sGenSets) * pHlyWeights(sSeasons, sDays, sHours) / pEfficiency(sGenSets, sYearsMod));

** Must list every equation in the dispatch investment model due to the separate demand adjustment model*
MODEL Dispatch_Inv / Objective2, eGenVarCost, eVoLLCost, eVoLCCost, eGenInvCost, eTxInvCost, eGenFOMCost, eDemandBalance, eMaxCap, eInitCap2, eNewCapExisting, eInstCapExisting, eTxMaxCap, eTxInitCap1, eTxInitCap2, eTxNewCapExisting, eTxInstCapExisting, eIntRetExisting, eInstCapCandY1, eInstCapCand, eIntNewCand, eTxInstCapCandY1, eTxInstCapCand, eInitCap1, eTxIntNewCand, eTxPairs, eTxPairs1, eTxPairs2, eTxPairs3, eTxPairs4, eTxPairs5, eTxPairs6, eTxPairs7, eTxPairs8, eTxPairs9, eTxPairs10, eTxPairs11, eTxPairs12, eTxPairs13, eTxPairs14.

# Annex 8: Selected detailed results

*Detail on forward-looking wholesale cost and the change in present value costs under different trade and access scenarios*

**Table 45 Forward-looking cost and its change compared to no trade – status quo access**

| Cost for the period 2019 to 2030 (US$2019 million) | No trade (S1) | Trade current no contrib. (S2a) | | Trade current contrib. (S2b) | | Trade current and new (S3) | |
|---|---|---|---|---|---|---|---|
| | Total | Change | Total | Change | Total | Change | Total |
| Fuel | 71,877 | -2,098 | 69,779 | -607 | 71,270 | -1,183 | 70,694 |
| O&M | 63,243 | -505 | 62,738 | -3,853 | 59,390 | -4,301 | 58,942 |
| Generation investment | 14,370 | -5 | 14,365 | -3,942 | 10,428 | -4,214 | 10,156 |
| Interconnector investment | 0 | 0 | 0 | 0 | 0 | 539 | 539 |
| Loss of load and insufficient capacity | 1,657 | -318 | 1,339 | 257 | 1,914 | 414 | 2,071 |
| **Total** | **151,147** | **-2,925** | **148,222** | **-8,145** | **143,002** | **-8,745** | **142,402** |

*Source: Authors.*

**Table 46 Forward-looking cost and its change compared to no trade – current state of progress**

| Cost for the period 2019 to 2030 (US$2019 million) | No trade (S1) | Trade current no contrib. (S2a) | | Trade current contrib. (S2b) | | Trade current and new (S3) | |
|---|---|---|---|---|---|---|---|
| | Total | Change | Total | Change | Total | Change | Total |
| Fuel | 72,616 | -2,141 | 70,475 | -651 | 71,966 | -1,214 | 71,402 |
| O&M | 63,499 | -523 | 62,976 | -3,845 | 59,655 | -4,326 | 59,173 |
| Generation investment | 14,851 | 59 | 14,911 | -3,960 | 10,891 | -4,188 | 10,664 |
| Interconnector investment | 0 | 0 | 0 | 0 | 0 | 492 | 492 |
| Loss of load and insufficient capacity | 1,680 | -319 | 1,361 | 279 | 1,959 | 447 | 2,127 |
| **Total** | **152,647** | **-2,924** | **149,723** | **-8,177** | **144,470** | **-8,789** | **143,858** |

*Source: Authors.*

**Table 47 Forward-looking cost and its change compared to no trade – universal access by 2030**

| Cost for the period 2019 to 2030 (US$2019 million) | No trade (S1) | Trade current no contrib. (S2a) | | Trade current contrib. (S2b) | | Trade current and new (S3) | |
|---|---|---|---|---|---|---|---|
| | Total | Change | Total | Change | Total | Change | Total |
| Fuel | 74,070 | -2,037 | 72,032 | -408 | 73,661 | -997 | 73,072 |
| O&M | 64,389 | -517 | 63,872 | -3,837 | 60,553 | -4,537 | 59,853 |
| Generation investment | 16,839 | 132 | 16,972 | -4,361 | 12,478 | -4,580 | 12,259 |
| Interconnector investment | 0 | 0 | 0 | 0 | 0 | 566 | 566 |
| Loss of load and insufficient capacity | 1,836 | -329 | 1,507 | 428 | 2,264 | 557 | 2,392 |
| **Total** | **157,134** | **-2,751** | **154,383** | **-8,178** | **148,956** | **-8,991** | **148,143** |

*Source: Authors.*

*CO2e emissions in the region under different trade and access scenarios*

**Table 48 Total $CO_2e$ emissions under different trade and access scenarios**

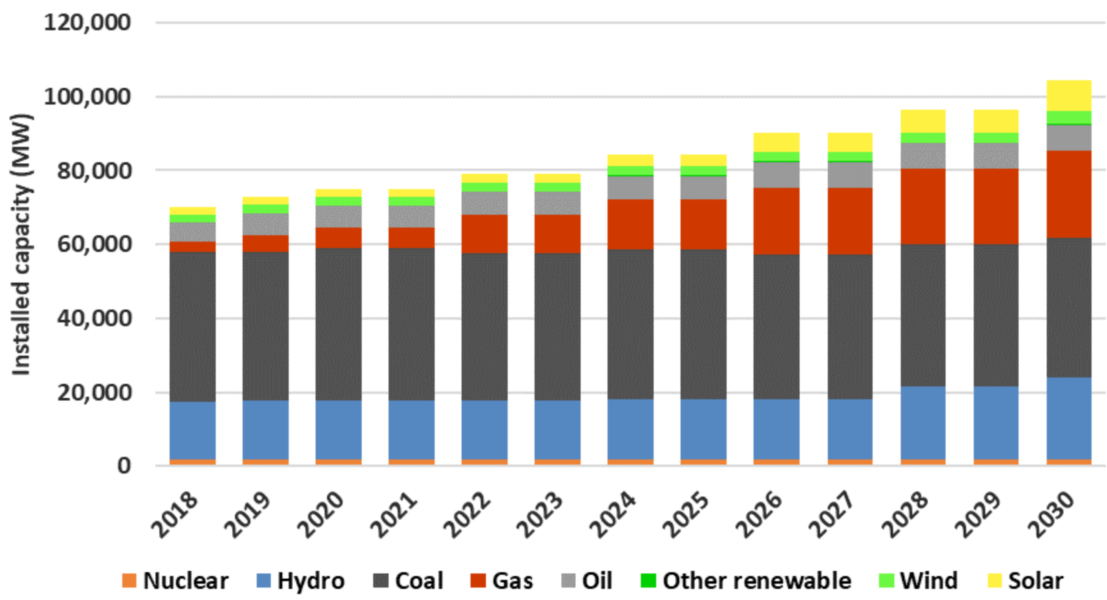
| Total $CO_2e$ emissions for the period 2019 to 2030 ($mtCO_2e$) | No trade (S1) | Trade current no contribution (S2a) | Trade current contribution (S2b) | Trade current and new (S3) |
|---|---|---|---|---|
| No incremental household connections | 2,783 | 2,711 | 2,690 | 2,668 |
| Current rate of progress in connecting new households | 2,800 | 2,727 | 2,706 | 2,683 |
| Universal access target achieved by 2030 | 2,831 | 2,765 | 2,745 | 2,717 |

*Source: Authors' calculations using emissions factors from Energy Information Administration (2020) and International Hydropower Association (2018).*

*Generation capacity in SAPP with and without trade under the universal access target*

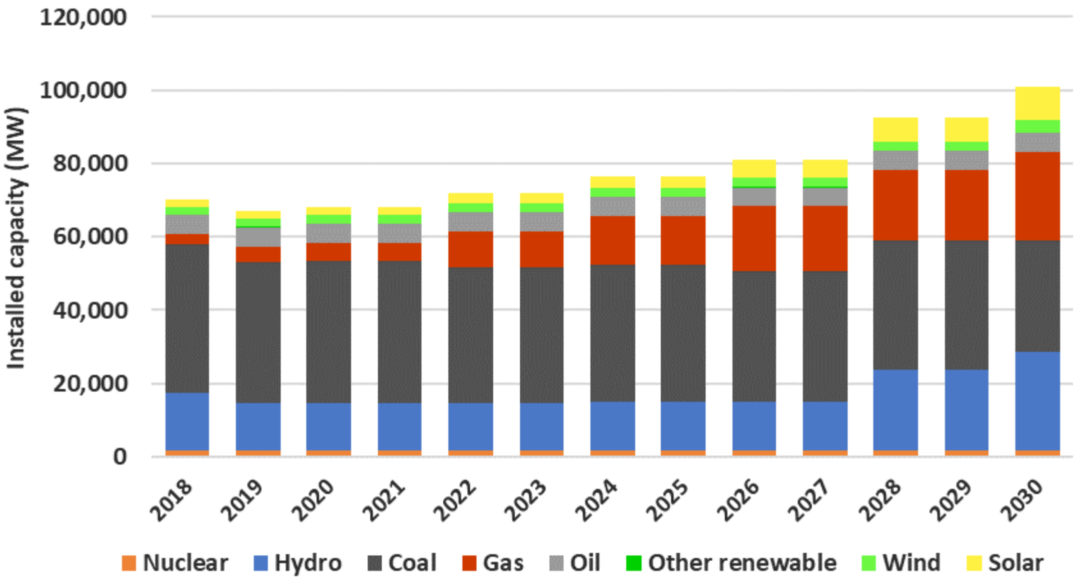
Today, due to the dominance of South Africa, most of the installed capacity in the region is coal (close to 60%), followed by hydro (22%), with much smaller shares of gas, oil, solar, wind and nuclear powered generation. Over time, the SAPP region is projected to reduce coal and oil fired generation capacity and increase gas, hydro and VRE generation capacity. This trend is more pronounced with trade. Overall, with trade South Africa develops less capacity and relies more on imports to meet demand. Forecast of generation capacity with and without trade is provided below.

**Figure 22: Generation capacity in SAPP with no trade (2018 – 2030)**




*Source: Authors.*

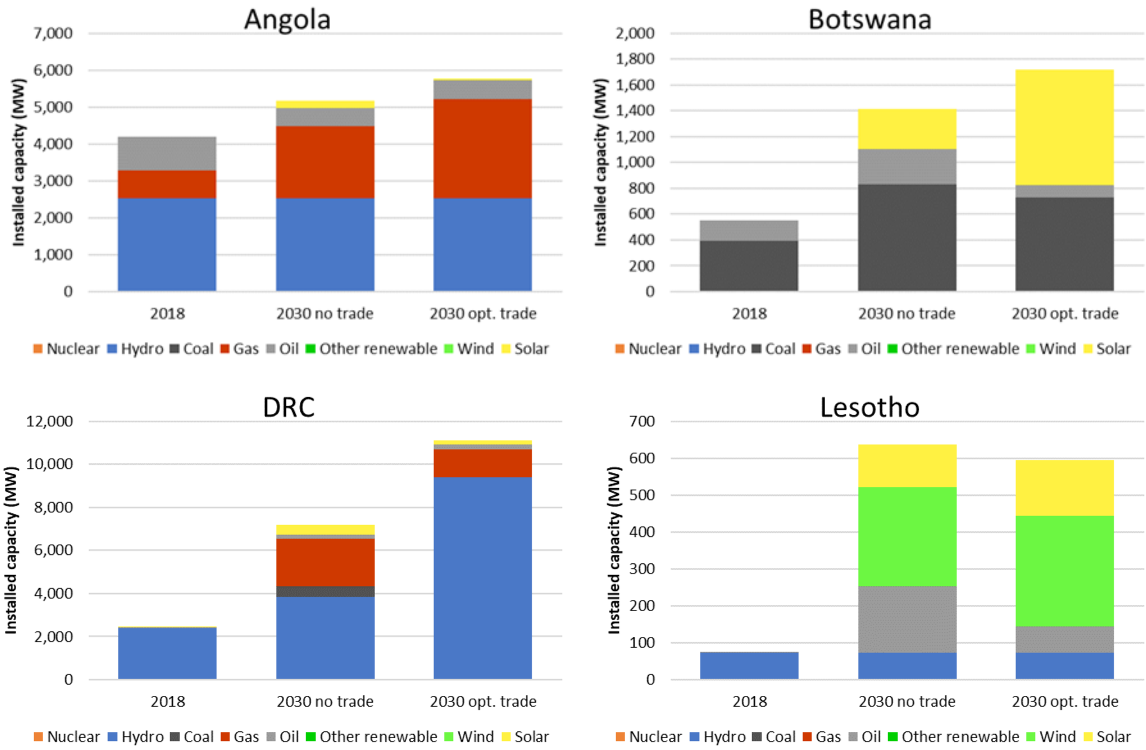
**Figure 23: Generation capacity in SAPP with full trade (2018 – 2030)**

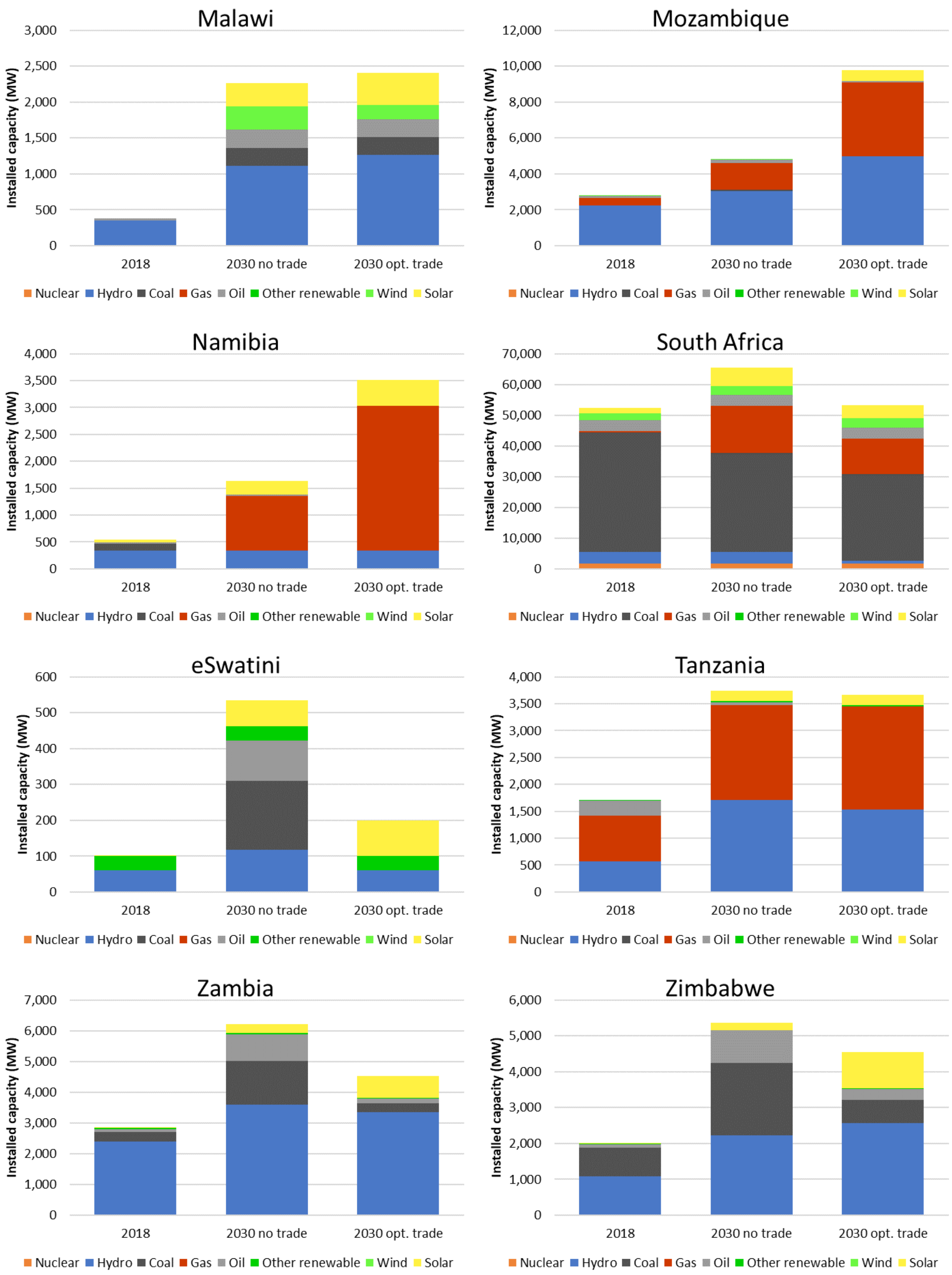


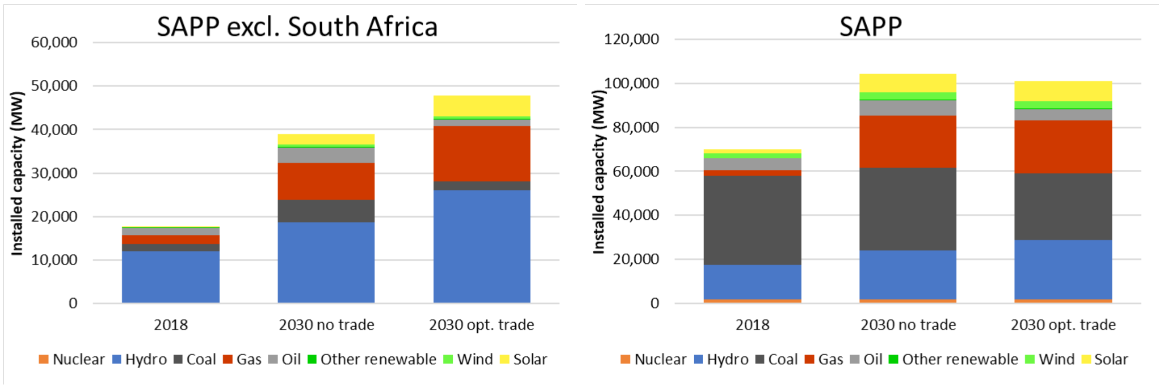

*Source: Authors.*

*Current and forecast installed generation capacity with and without trade under the universal access scenario*

**Figure 24: Current and forecast generation capacity with and without trade**




Malawi
3,000
2,500
2,000
1,500
1,000
500
0
Installed capacity (MW)
2018
2030 no trade
2030 opt. trade
Nuclear Hydro Coal Gas Oil Other renewable Wind Solar
Mozambique
12,000
10,000
8,000
6,000
4,000
2,000
0
Installed capacity (MW)
2018
2030 no trade
2030 opt. trade
Nuclear Hydro Coal Gas Oil Other renewable Wind Solar
Namibia
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Installed capacity (MW)
2018
2030 no trade
2030 opt. trade
Nuclear Hydro Coal Gas Oil Other renewable Wind Solar
South Africa
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
Installed capacity (MW)
2018
2030 no trade
2030 opt. trade
Nuclear Hydro Coal Gas Oil Other renewable Wind Solar
eSwatini
600
500
400
300
200
100
0
Installed capacity (MW)
2018
2030 no trade
2030 opt. trade
Nuclear Hydro Coal Gas Oil Other renewable Wind Solar
Tanzania
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Installed capacity (MW)
2018
2030 no trade
2030 opt. trade
Nuclear Hydro Coal Gas Oil Other renewable Wind Solar
Zambia
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Installed capacity (MW)
2018
2030 no trade
2030 opt. trade
Nuclear Hydro Coal Gas Oil Other renewable Wind Solar
Zimbabwe
6,000
5,000
4,000
3,000
2,000
1,000
0
Installed capacity (MW)
2018
2030 no trade
2030 opt. trade
Nuclear Hydro Coal Gas Oil Other renewable Wind Solar




*Source: Authors.*

# Annex 9: Matrix of comments and replies to referees

This annex summarises comments and suggestions for improvements made by my opponents and the members of the Committee with respect to the pre-defence version of my dissertation thesis. I then provide replies to each of the comments and summarise edits made to the thesis following each of the comments received.

Here I would like to also take the opportunity and express my gratitude for the comments and the time of my opponents and the Committee spend on providing valuable comments that enhanced my research and also provided interesting avenues to explore in my future research. I hope that my replies are sufficient and meet all requirements. The order of comments and my replies follows the order in which the respective comments were received.

This version of the dissertation thesis also addressed additional comments received from the journal referees in which each respective research paper was published - Journal of Economic Surveys (Chapter 2) and Energy Policy (Chapter 3) - or was invited for revised submission - Energy for Sustainable Development (Chapter 4).

| **Comments made by opponents and members of the Committee** | **Replies and edits made to the thesis in response to the suggestions** |
|---|---|
| **1. Opponent's comments - Prof. Ing. Karel Janda M.A., Dr., Ph.D. (IES)** | **My replies to comments and suggestions made by Prof. Ing. Karel Janda M.A., Dr., Ph.D.** |
| **Introduction (Chapter 1)**: I would recommend removing both quotes at the beginning. These quotes are not really needed there because in this particular case their content is rather obvious. I think that everybody is aware of the importance of finance and energy for economy, including developing economies in Africa. | Thank you. I have removed the two quotes from the revised version of my dissertation thesis. |
| **Costs of access (Chapter 3):** I consider this paper well fitting into the formal of this journal and my expert opinion is that this paper has a good chance to be invited by Energy Policy editor for Revise-and- Resubmit. So, I expect that the version submitted to final thesis defense will address the issue raised by the Energy Policy referees. | Indeed, we received a Revise-and-Resubmit decision in May 2020 and resubmitted the article to Energy Policy in June in which we incorporated all the comments received from the journal. The manuscript was accepted for publication in Energy Policy in September 2020 and published in January 2021. The version of the article contained in this thesis incorporates comments received during the peer review process. The published manuscript is available here: https://doi.org/10.1016/j.enpol.2020.111935. |

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| **Costs of access (Chapter 3):** On page 47, I understand the policy emphasize for Energy Policy submission, nevertheless I think that Sustainable Development Goal reference in the abstract is not really fitting – abstract should focus on original research contribution of the paper, not on providing general context connections. | Thank you for the guidance. I have removed the reference to Sustainable Development Goal number 7 in the abstract. |
| **Costs of access (Chapter 3):** Given an increasing demand of journals for providing all data and computational details enabling replication of published papers, it would be nice to include into this thesis also a computer code used for core optimization content of this chapter. | This is a good suggestion. I have provided the core code of the optimisation model used for the analysis in Chapter 4 (which builds on the code built for Chapter 3), including the variables, equations and the objective function in the revised version of the thesis (please refer to Annex 7). |
| **Regional trade (Chapter 4):** As opposed to Journal of Economic Surveys and Energy Policy, I am not familiar with Journal of Sustainable Development to which this paper was submitted in April 2020. I am not sure that this is the most suitable outlet for this paper. I think that the research on this Sub-Saharan electricity model provided enough results for a second paper (in addition to a leading Energy Policy paper) to be published in respected journal covered by WoS and Scopus. | Thank you for having noted this. The article contained in Chapter 4 of my thesis entitled *Potential gains from regional integration to reduce costs of electricity supply and access in Southern Africa* was submitted to Energy for Sustainable Development (i.e. not Journal of Sustainable Development). I have corrected this inaccuracy in the revised thesis. We received a revise and resubmit decision in October 2020 and we resubmitted our manuscript in December 2020 incorporating all the comments received during the peer review process.<br><br>The version contained in this revised version of my thesis incorporates comments received during the journal review process as well as comments received from reviewers at Charles University and during the pre-defence of my thesis in October 2020. At the time of finalising this thesis (February 2021) we are still waiting to hear back from the journal Energy for Sustainable Development. |
| **Regional trade (Chapter 4):** The topic of electricity interconnection may also by treated with ELMOD model – see the set of papers by Janda, Malek and Recka dealing with application of ELMOD to Central Europe. | My understanding of ELMOD is that while it does model electricity interconnection, it does not include endogenous investment decisions in generation or interconnectors. Instead, investments are an exogenous input to ELMOD and it simulates the <u>operation</u> of the power network. |

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| | Excluding investment decisions allows ELMOD to have a detailed representation of the power system in the short run, including a DC load flow representation of transmission, which my model does not include. ELMOD therefore is more appropriate for investigating operational effects of policy decisions. For example, investigating the effect on the Czech power system of intermittent generation in Germany (where flows from surplus wind in Northern Germany to demand in Southern Germany take routes directly through Germany, but also through NL-BE-FR, and PL-CZ), which was one of the topics of the papers by Janda, Malek and Recka.<br><br>In contrast, my research investigates the long term cost of meeting access targets with and without trade, which means I need to take into account both investment costs and operating costs. For this reason, ELMOD would not have been appropriate for my research.<br><br>An extension to ELMOD, dynELMOD has been developed more recently that includes endogenous investment decisions for generation, storage and transmission in 5 yearly intervals. In its current form, with 5 yearly time intervals, dynELMOD would not have been suitable to analyse the costs of reaching different access targets in 2030.<br><br>In the Introduction to Chapter 3, I have added a reference to ELMOD and papers by Janda, Malek and Recka regarding application of ELMOD to Central Europe, and also a reference to dynELMOD. I have also added a discussion of other energy modelling frameworks to Chapter 3. |
| **Regional trade (Chapter 4):** On a supply side, more attention could be given to renewable energy, problems with its intermittency and connection with hydro-energy (especially the pumped-storage hydroelectricity). | This is a good insight. While intermittent generation from renewable energy sources such as solar PV and wind is an issue for the power sector, both hydro storage and battery storage can help to mitigate the effects.<br><br>Power sector simulation modelling requires trade-offs to ensure the model is computationally tractable while providing useful insights. It is computationally intensive to model storage and very computationally intensive to model stochastic generation. Given that my focus in chapter 4 was on the long run effects of regional integration on |

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| | the wholesale cost of supply under different electricity access scenarios in the SAPP region, I traded off a longer planning horizon and generation and transmission investment decision making against other features such as a more detailed representation of intermittent generation and hydro storage.<br><br>In addition, I was aware that the optimisation model understates variance in both generation and consumption. For this reason, the model includes a generation capacity requirement for planning purposes, with a penalty if the margin is not met. Otherwise, understating variance would tend to understate the quantity of generation or interconnector capacity required in the model.<br><br>Finally, I also took the view that the effects of understating generation and consumption variation would be somewhat offset by the effects of understating the flexibility of storage, which understates the flexibility of the power system to respond to variations in generation and consumption.<br><br>I have added a brief discussion about trade-offs between the representation of supply and demand variation in the model and the need to capture generation and transmission investment decisions in Annex 3. In the conclusion of Chapter 4, I have also suggested that modelling spinning reserves would be an interesting extension to the study in the light of increasing VRE generation in the SAPP power system. |
| **Regional trade (Chapter 4):** On a demand side, behavioral characteristics (like possible very high demand for air-conditioning) should be carefully taken into account. | Since the primary focus of my research was to look at the supply side and look at the generation needs and associated investment needs under different levels of regional integration and electricity access scenarios, I did not attempt to do a bottom-up demand estimation. In theory I could have based my demand assumptions on work done by others in this area, with the most comprehensive demand forecast undertaken to date for the SAPP region to the best of my knowledge being that found in the SAPP Pool Plan (2017).<br><br>SAPP Pool Plan (2017) is a detailed bottom-up demand forecast for the period 2017-2040, |

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| | estimated using key demand drivers such as the assumed economic growth in the various sectors of the economy and their share in GDP, the assumed number of new customers connected to the main grid, when this information was available, and the assumed consumption patterns of both existing and newly connected customers. However, as I note in my thesis, already today we can see considerable differences between the SAPP forecast from 2017 and actual data as reported by utilities.<br><br>Since deriving a demand forecast for each of the 12 countries and considering all the key demand drivers could be another thesis in itself, I based my analysis on a thorough review of residential and non-residential demand of existing customers (as per annual reports of utilities, integrated resource plans and the SAPP master plan) and their likely trajectory and compared my demand forecast to that in SAPP Pool Plan (2017) as well as to recent demand growth.<br><br>My demand projection broadly corresponds to the low-case scenario in the SAPP Pool Plan (2017), which forecast 2.4% annual growth in sent-out demand across SAPP countries over the period 2019 to 2030 (I note that the assumed number of new connections during that forecast period is not available in the SAPP plan). In my analysis the assumed growth rate in end-consumer demand for electricity (keeping the level of technical losses largely constant) varies by the electricity access target and is:<br>• 2.3% under the 'Current rate of progress' (3.3% if SA is excluded from the average); and<br>• 2.6% under 'Universal access target' (4.6% if SA is excluded from the average).<br><br>For demand of newly connected customers, I followed OECD/IEA (2017) and assumed that a newly connected urban household will consume 500 kWh per year and a newly connected rural household 250 kWh per year, growing at 4% per annum over the forecast horizon. In view of the limited number of appliances households would be able to power when consuming only 250-500 kWh per annum, I also ran a scenario under which the starting point of consumption is significantly |

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| | higher when estimating the cost of providing access (i.e. starting at 1,000 kWh and 500 kWh per annum in urban and rural areas, respectively). I believe that this range of possible demand scenarios of newly connected households is adequate, also in view of the limited ability of households to pay for electricity (Blimpo et al., 2019; IEA, 2020) and tariff levels being generally higher in SSA than in developed countries (WB, 2009; IMF, 2013; Trimble et al., 2016).<br><br>My objective was also to provide an estimate of the costs of a consumption bundle that is considered sufficient to meet basic electricity needs, which takes into account trade-offs people are facing due to affordability issues between their energy needs and other demands. For example, 500 kWh per household per year would allow for electricity services sufficient to power a mobile phone, four lightbulbs operating for a few hours a day, a fan for three hours a day and a television for a few hours a day using standard appliances (IEA, 2020b). Since the affordability among rural households is likely to be more constrained, I assumed an initial consumption of 250 kWh per household per year, as discussed above and in line with OECD/IEA (2017). The extended consumption bundle would additionally allow for a refrigerator and increase the number of hours that the fan and television are used (IEA, 2020b). By way of context, the subsistence level of consumption is usually defined as 30 kWh/month per household (Foster and Rana, 2020; Kojima et al., 2016).<br><br>I have added a brief discussion on this to the revised thesis (section 3.4.2), saying that the objective is to provide an estimate of the costs of meeting basic electricity services and taking account of likely trade-offs household are facing in the region. |
| **Regional trade (Chapter 4):** Looking at the acknowledgement of this thesis, it looks like Nicholas Elms may be a co-author of both energy papers. If this is the case, please indicate this at the beginning of the particular chapters in the similar way as Roman Horvath and Tomas Havranek are indicated as co- | This is indeed the case and Nicholas Elms is the co-author of both energy papers. This has now also been clearly added before each of the energy chapters. |

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| authors of the meta-analysis paper. | |
| **General**: On page 53 (and elsewhere in the dissertation): please use either Annex or Appendix terminology (you use Annex in the text and Appendix in the Annex). | Thank you. I have corrected for this in the revised version of my dissertation thesis. |
| **2. Opponent's comments - Claire Nicolas Ph.D., (Energy Sector Management Assistance Program - ESMAP)** | **My replies to comments and suggestions made by Claire Nicolas Ph.D.** |
| **Introduction (Chapter 1)**: The introduction could be slightly modified to emphasize a bit more the link between financial service availability and energy access in the developing world context. An idea could be to exploit a little bit more the supposed link between financial services and access/electricity uptake. | Thank you for the comment. I have added a few paragraphs to the introductory chapter, discussing the importance of financial services in overcoming credit constraints to soften affordability issues, and hence to unlock latent demand for electricity access and its use. |
| **Fin-growth paper (Chapter 2)**: The findings are interesting and could be put more in perspective in the context of development particularly since the results suggest that the structure of a country's financial system is important as well as its level of development. What does it mean for developing countries? This question could be addressed in the introduction or the conclusion as I don't think chapter 2 needs to be modified. | Thank you for the comment and I have taken this into account in the revised thesis. Indeed, there are important conclusions to be taken from the analysis and conclusions that are pertinent to developing countries.<br><br>First, my results from the multivariate meta-regression shed light on how to conduct future research analysing the impact of financial development on economic growth in general and also specifically in developing countries. That is, the different regional effects clearly show that it is not sensible to pool different regions as the estimated impact of finance on growth is not stable across regions (i.e. primary studies should control for region and potentially the level of development in their estimations).<br><br>Second, the different regional effects suggests that for countries at a lower stage of development (e.g. those in SSA and South Asia), other factors might be more important to focus on initially than trying to expand certain aspects of the financial sector e.g. the stock market (one would need to look at similar studies ideally using meta-analysis and looking at other potential contributors to growth and compare their relative importance). It is worth noting, however, that the primary studies included in the meta-analysis did not consider measures of |

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| | financial inclusion and it would be interesting to see whether higher levels of financial inclusion support economic growth.<br><br>When conducting analysis of the impact of financial development on economic growth, one also must have in mind data availability. One of the biggest challenges for empirical research in this field as discussed in Chapter 2 is finding good proxies for financial development. The most used indicators of financial development can be broadly defined as financial depth, the bank ratio and financial activity. These metrics for countries in SSA are, however, scarce. Even according to the most recent data contained in the Global Financial Development Database from October 2019, data on bank ratio are only available for 3 countries in SSA. Data are also very scarce for the market capitalisation ratio (4 data points in SSA) and the market turnover ratio (3 data points in SSA), whereas metrics like the share of population with a money account are readily available. The latter could be used as a proxy for financial development when looking at less developed countries (however, this proxy was not used in primary studies, given the lack of data, but suggests clear avenues for future research).<br><br>I have added a discussion on this to Chapter 2, including suggested areas for future research. |
| **Costs of access (Chapter 3)**: P64: if I am not mistaken the 2 equations are the same, the only thing changing being the scenario name. Indeed, in both cases the optimization problem is the same with some exogenous assumptions being modified (the demand in this case). I would delete equation (2) and slightly reformulate the text around to make that clear (text p64 and 65). | That is correct, the 2 equations were the same with only demand changing between them, and with demand defined exogenously to the model. In the revised version I have deleted the second equation and reformulated the surrounding text. This makes the interpretation and understanding indeed much clearer. |
| **Costs of access (Chapter 3)**: P.66: While equation 3 [*now equation 2 in the revised submission*] is quite clear, I am not sure I get the first bullet point's point. The authors talk about the difference between: C(Target access rate*)-C(Status Quo*) yet in the equation (3) I see no difference, it looks | Thanks for noting this. Equation (2) in Chapter 3 in the revised submission is the levelized <u>*incremental*</u> cost of meeting the access target. To calculate the levelized cost of meeting the incremental demand due to access, I divide the present value of the change in cost between the chosen access scenario and the status quo, by the present value of the change in consumption |

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| like a regular LCOE equations (except for the IE in the denominator). | between the chosen access scenario and the status quo.<br><br>This is different to a regular LCOE calculation, which considers overall costs and overall demand. This was not very clear before but I have rewritten the formula and the first bullet point to the equation to make this point clear and to avoid any confusion with respect to a standard LCOE calculation. |
| **Regional trade (Chapter 4)**: Since one of the findings of the paper is that half of the possible cost savings from existing interconnectors is due to efficient sharing of reserve capacity between countries, it would be interesting as a next step also to consider spinning reserve needs in the model. Particularly since hydro (a potential flexibility provider), wind and solar are going to represent a growing share of the installed capacity. | This is a good comment since spinning reserves will become more important over time, as we have seen in countries such as Ireland and the United Kingdom.<br><br>The minimum capacity requirement imposed in the model includes a margin over peak demand to allow for planning and other standing reserves and also for the capacity needed to provide spinning reserves. However, we do not consider the dispatch effects of spinning reserves (i.e. the need for power stations to have some spare capacity to ramp up quickly or ramp and down quickly to maintain the supply-demand balance on the system). Given that transmission interconnectors can deliver spinning reserve from one region to another, not modelling the dispatch effects of spinning reserve is likely to understate the benefits of transmission.<br><br>I have including a discussion of spinning reserves in the revised version of the thesis as a possible extension to the work, in the concluding section of Chapter 4. This extension would require investigation of drivers of spinning reserve requirements in the SAPP region (variation of demand and intermittent generation output and n-1 security constraints), understanding of the possible contribution from each generation technology to meeting that requirement and re-coding the model to include dispatch constraints to reflect the spinning reserve requirement. |
| **Regional trade (Chapter 4)**: Another issue that could be considered to continue exploiting this SAPP model is whether the results obtained in this paper are robust to drought episodes in the region. Indeed, it seems that | This is a very good suggestion. Our analysis does suggest an increasing reliance on hydropower with optimal trade compared to no trade, which in turn may pose risks due to the variance of hydro inflows, and due to the uncertain impacts of climate change, e.g. possible increased variability |

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| droughts are becoming more frequent and since the results seem to suggest decommissioning some baseload capacity (coal in South Africa) to invest in more hydropower, exploring the impact of droughts on generation investment under trade could be interesting. | in generation output of hydropower and possible reductions in average hydro inflows, which we saw in 2019.<br><br>I note that these impacts are likely to vary by region and even locally, with some hydro sources being more susceptible to droughts whereas others perform better with a more stable capacity factor. For example:<br>• IRENA (2013) notes that while Angola is well endowed with large hydro resources, these perform very poorly in a dry year, whereas the Inga hydro plants on the Congo river are very reliable;<br>• during the recent drought of 2019/2020 we saw Kariba output reduced while Zimbabwe turned to imports from Mozambique, in part because HCB continued to operate largely as normal.<br><br>That is, hydro inflows are not perfectly correlated in the different catchments in the SAPP region or even at different locations in the same catchment area. Therefore, it is likely that a reduction in hydro generation in only one region of SAPP or increased inflow variation where the inflows of different regions are not closely correlated would increase the value of interconnectors.<br><br>There are various different ways to represent droughts. Where the effects of climate change are known to be reducing river flows, this can be captured by a deterministic reduction in availability of hydro generation sources. However, where the variation in hydro flows is increasing (more frequent or more serious droughts and rainy periods) a stochastic approach should be used such that the model is "surprised" by a drought.<br><br>Since the least-cost optimisation model is not a stochastic model, limiting the possibility to analyse the effect of increased variation in hydro generation, I have followed the first approach and included two sensitivities on hydro generation. These are included under 'Sensitivity analysis' in the results section under Chapter 4. Specifically, I look at:<br>• A scenario with No Grand Inga; and<br>• An impact of a localised drought. |

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| | However, due to the fact that the model has perfect foresight over the forecast horizon, it is not possible to draw generalised conclusions from the drought sensitivity.<br><br>Not being able to model stochastic generation is a common drawback of least-cost optimisation models. For example, IRENA relies on MESSAGE which also does not allow stochastic generation to be modelled due to limitations of the modelling framework. In order to take into account periods of droughts in their modelling framework, IRENA relied on a 'dry-year' capacity factor for all hydro sites and across all the modelled scenarios (see IRENA, 2013). This approach would, however, understate the output from hydropower, potentially leading to below optimal hydro development in the region. |
| **Regional trade (Chapter 4)**: Figure 13: Why are Lol and insufficient capacity costs higher in the scenarios where interconnectors contribute to the capacity requirement than in the no trade and no contribution scenarios? Because LoL is higher due to the lower capacity investment? | Correct. For the scenarios where transmission import capacity contributes to the installed capacity requirement in a country, less generation capacity is built in the region overall and therefore there is greater loss of load.<br><br>For example, with 100% access in 2030 and current interconnectors, the scenario where interconnector import capacity contributes to the installed capacity requirement has about 5,650 MW less capacity in the SAPP region than the scenario where interconnectors do not contribute to the installed capacity requirement.<br><br>It is reassuring that differences in the cost of loss of load between scenarios have only a small contribution to the overall system costs. If changes to the cost of loss of load were a significant driver of overall costs the concern would be that the overall result could be an artificial construct due to our modelling assumptions.<br><br>The reason for the observed changes to costs is clarified above Figure 11 in the revised version of my thesis. |
| **Regional trade (Chapter 4)**: Figures 14 and 15: could facilitate the reader experience to plot the difference between those 2 graphs. As it is it is not easy to see the difference. | Thanks for the suggestion.<br><br>Based on this feedback, I have now included only the difference between the two charts as this allows the reader to better see the impact of trade |

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| | on the generation capacity in the region (please refer to Figure 12 in the revised submission). The key changes are an overall reduction in generation capacity, with less coal and more hydro capacity by 2030. I have moved the other two charts to Annex 8, where I show selected detailed results. |
| **Regional trade (Chapter 4)**: Figure 16 [*now Figure 13 in the revised submission*]: if doable, it could be worthwhile to add one dimension to this graph by showing the utilization rate of the interconnector (with e.g. a color scale or varying width for the arrows). That would allow the reader to immediately get a sense of the direction of the flow and to identify the main corridors easily. | This is also a good suggestion. I have added shading to the chart to portray the interconnector utilisation in each direction with the darkest shading for the greatest annual flows. |
| **Regional trade (Chapter 4)**: South Africa seems to become a large importer. Is that the case? Which share of its demand would be imported? If that is a large share, a quick discussion on energy security could be welcome. | This is a very good observation. In our modelling, as South Africa decommissions aging coal plants it increasingly imports power to meet demand, reflecting the cheaper generation options available outside South Africa. In 2024, imports are 5% of demand, 6% in 2026, 12% in 2028 and 18% in 2030. The scenario with optimised interconnection is intended to show the possible economic benefits of interconnection. However, overcoming policy constraints due to perceived or real security of supply issues is needed to capture those economic benefits. Therefore, I have added a brief discussion about security of supply issues to the results section of Chapter 4 of the revised version of the dissertation thesis.<br><br>Indeed, the South African Department of Mineral Resources and Energy published its IRP 2019 in which it includes 10,500 MW of old coal power station decommissioning by 2030. The plan does consider regional integration and includes 2,500 MW of imported hydro from Grand Inga by 2030. However, the plan also raises security of supply issues and the possibility of forcing into the plan new coal plants in South Africa, which I have also added to the revised version of the thesis.<br><br>Finally, I have also added a calculation Herfindahl-Hirschman index (HHI) as a measure of diversity of primary energy supply in the region, which I calculate both under no trade and |

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| | optimal trade scenario using existing and new interconnections. |
| **3. Opponent's comments - Mgr. Milan Ščasný PhD. (IES)** | **My replies to comments and suggestions made by Mgr. Milan Ščasný PhD.** |
| I would appreciate a brief discussion on the conceptual, economic, and econometric model to analyse properly the association between financial development and economic growth. | Thanks for this comment.<br><br>A number of different econometric specifications could be used with the overarching conclusion that it is important to control for omitted variable bias and address possible endogeneity issues. To the revised version, I have added a brief discussion on the key channels through which financial systems have the potential to enhance economic growth. I have also provided a reference to other research work that provides an overview of the empirical studies examining the effect of financial development on economic growth, methodologies used to study their relationship, as well as a discussion on the wide variety of empirical findings derived from diverse empirical studies using different estimation techniques, specifications and data characteristics. |
| Since all studies reviewed in the meta-analysis rely on aggregated data, their results may suffer due to many biases.<br>i) First, similar studies have discussed how the dependent variable shall be defined, whether as a scale variable or as growth (all reviewed studies seemed to rely on the latter) that may have also consequences on the model specification.<br>ii) Second, the effect (the association) need not be immediate and certain time may be required to transfer the effect of controlled variable on the dependent variable. Stationarity and other problems might be treated (partly) by how the model is specified. How the original studies reflected these issues?<br>iii) Third, similar studies based on similar datasets (as the original studies) suffer from the aggregation bias that is likely | I agree that results contained in primary studies may suffer from several biases. This was one of the reasons for doing a meta-analysis, where I controlled for possible misspecification when estimating the impact of financial development on economic growth (e.g. the fact that authors do not address endogeneity when estimating finance-growth impact, whether the impact is weaker/stronger in some regions compared to others or over certain time periods, etc.).<br>i) Indeed, different measures of economic development are used in the empirical growth literature. However, in my analysis I considered only studies where the dependent variable in the growth equation is the growth rate of GDP per capita or growth rate of GDP in real or nominal terms (i.e. the focus of the analysis was on classical growth regressions augmented for financial development). This was also one of the selection criteria for the inclusion of primary studies in the meta-analysis since I had to limit the number of studies to be included and also to increase comparability. I have clarified this point in the revised version of my thesis. |

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| profound when the data are averaged over years or even over a decade.<br>iv) Fourth, studies using aggregate data may also suffer from the omitting variable bias that may be treated by time-, country-, or time and country- specific fixed effects. While some original studies may use the first two, I worry whether there is any to control for the interaction term that allows to control for an effect of specific condition in given country in given year. | ii) I agree that the effect might not be immediate. Some researchers deal with that by averaging observations over longer periods, analyse data over a longer period of time to abstract and adjust for business cycle fluctuations or using a lagged value of financial development. In the multivariate meta-regression (MRA), the variable length, is found to be positive and significant, which corresponds to the findings of Calderon and Liu (2003). This suggests that the effect of financial development is higher in the long-run. I have added this discussion to the revised version of the thesis.<br>iii) This is a good point. Further to that, averaging observations over longer time intervals is associated with information loss. Nevertheless, using averaged data over longer time intervals has been commonly used among studies analysing the relationship between financial development and economic growth with data most frequently averaged over 5 years instead of using a higher frequency data (e.g. quarterly or annual). Data are averaged over a longer time horizon in order to abstract from business cycle fluctuations as noted by for example Beck and Levine (2004). The research in the field has generally focussed on evaluating long-term relationships between financial intermediaries, stock markets and economic growth, thus averaging data over longer time periods. An interesting finding by e.g. Loyza and Ranciere (2006, p. 1069) is that "*a positive long-run relationship between financial intermediation and output growth can coexist with a negative short-run relationship*". I have added this discussion to the revised version of the thesis.<br>iv) Some studies use a fixed effects (FE) model to control for specific country characteristics, which solves the issue of omitted variable bias due to unobserved country or region-specific effects. However, this technique does not specifically deal with the issue of endogeneity bias. On the other hand, a |

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| | | random effects (RE) model addresses the issue of endogeneity but does not address the bias resulting from country specific effects. Hence, both FE and RE provide only half of the solution to the problem of omitted variable bias and simultaneity bias. Tsangarides (2002) discusses these issues in detail. Fixed effects estimation has been used in 11 out of 67 studies and random effects estimation in just 4 studies. To address both issues at once, researchers studying the relationship between financial development and economic growth have been relying on the Generalized Method of Moments estimator (GMM). GMM has been employed in 33 journals in the study sample. Based on the GMM estimation results, Levine et al. (2000, p. 44) note: "*we can safely discard the possibility that the relationship between financial intermediary development and growth is due to simultaneity bias or to omitted variables*". A system GMM estimator is now commonly used in the empirical growth literature and is often referred to as a best practice estimator for dynamic panels. In the multivariate meta-analysis, I included a moderator variable that controls for endogeneity, which is a dummy variable (it equals one if endogeneity is addressed), with the objective being to assess whether not correcting for possible endogeneity bias in the primary studies leads to different estimation results, and hence possibly reporting biased results. I have now also added a discussion on the econometric approach used in the empirical literature.<br><br>I agree that aggregating data over different regions / countries and data periods suffer from several biases. This is also supported by the findings of the meta-regression analysis. Specifically, the findings show that the finance-growth impact vary by country/region and time period. This finding has an important implication for future research as it is apparent that it is not sensible to pool different regions together since the estimated effects are not |

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| | stable across regions. The effect seems to be smaller in less developed countries (SSA) and higher in richer countries (Europe). This suggests a pattern where a certain level of financial and economic development increases the growth effect of financial development, supporting the view that the effect may also vary over time. In order to investigate the differences in the finance-growth effect for different time periods, decade dummies have been included in the MRA (1980s as the baseline). The results suggest that the effect of financial development declined in the 1990s compared to the 1980s (consistent with Roussuau and Wachtel, 2011). However, the evidence also gives support to the conclusion that the growth effect of financial development for the twenty first century is not significantly different from the 1980s. |
| **Chapter 2: Data measurement (in the original studies)**: Some studies used nominal GDP (not per capita) as the dependent variable and I do not see any good reason for it. Please could you explain reasoning of using nominal, not real, and the growth in levels, not the growth in per capita levels, in some of the reviewed studies? | The nature of the dependent variable used in the primary studies (67 studies, 1334 estimates) was as follows:<br>• most studies relied on G*rowth rate of real GDP per capita* as the dependent variable (960 estimates),<br>• followed by *Growth rate of real GDP* (188 estimates);<br>• *Growth rate of nominal GDP per capita* (103);<br>• *Growth rate of nominal GDP* (83 estimates).<br><br>Nominal versus real: about 14% of the estimates relied on nominal GDP values with the rest relying on real values.<br><br>Growth in total GDP versus per capita values: about 20% of the estimates relied on growth in total GDP with the rest relying on per capita values (real or nominal).<br><br>My thinking is also that the objective of the primary studies would be to understand real wealth effects in per capita terms. One reason for using nominal values cold be if the input into the regression is a nominal value, e.g. the nominal |

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| | size of the banking sector or nominal value of the stock market. Where researchers do not adjust for the number of people (i.e. use growth of the economy as a whole), they could control for the size of the population among the control variables. The specification is likely to be driven by the nature of the primary studies and the underlying research question (e.g. studies looking at business cycles generally use the change in total GDP).<br><br>I have clarified in the revised version that since the focus of the meta-analysis was to quantitatively analyse studies relying on classical growth regressions, only studies using GDP growth rates as the dependent variable were considered (section 2.3). |
| **Chapter 2: Reasoning & motivation for the research.** Usually, one may find several well performed and several not so well performed studies while reviewing the literature. What is then a reason to perform a meta-analysis using studies that were not well performed? For instance, the estimates are likely biased if endogeneity is not addressed (49 % estimates, or studies?), it may suffer heavily if working with aggregated data over years (panel?, 62% estimates), or even over a decade (cross-section?, 20% estimates). Yes, you correctly concluded that "Our results suggest that it is important to control for endogeneity when estimating the effect of finance on growth" (page 40), but we have known this even if the meta-analysis was not carried out. Would be better to run your model with all observations that applied not proper methodology and/or were likely suffering due to some of the biases excluded? | Meta-analysis is a quantitative literature review, a way to summarise empirical results from primary studies in a more systematic and transparent way than classical literature reviews. The primary objective is to shed light on why there is such a big variation in research findings (which was the case for the empirical relationship between financial development and economic growth). By conducting a meta-analysis, we can better understand why certain studies tend to report a higher / lower effect than others and whether certain results are more likely to get reported than others (file drawer problem or publication bias) and to control for these issues. Standard literature reviews would not allow the researcher to control for all these effects at once and understand why results in primary studies vary so much.<br><br>Correct, about half of the estimates were derived using a specification that does not adjust for endogeneity issues. When performing the meta-regression analysis, while I control for potential endogeneity issues, studies that do not address endogeneity (i.e. employ for example simple OLS) are included in the estimation.<br><br>To reflect these comments as well as the discussion during the pre-defence of my dissertation thesis, I have added to Chapter 2 a reference to some novel meta-analysis techniques increasingly used since the time of publishing my research findings. |

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| **Chapter 2: Results**<br>Association with GDP is positive and significant, while the association with GDP per capita is not distinguishable from zero. I am puzzled seeing this result. Would be the effect of the studies that used GDP level indicating rather the effect of the size of a country. | With respect to the dependent variable used in the primary studies, most researchers relied on *Growth rate of real GDP per capita*, hence this is used as the base / reference category in the meta-regression. Table 5 then reports whether using a different specification (i.e. the reliance on a different measure of financial development in the growth regressions) would lead to systematically different results. That is, what the results say is that relying on *Growth rate of nominal GDP per capita* does not lead to systematically different results to using the *Growth rate of real GDP per capit*a. The coefficients for moderator variables *Growth rate of real GDP* and *Growth rate of nominal GDP* are found to be positive and statistically significant (i.e. studies that in their specification use the growth rate of real or nominal GDP, i.e. not in per capita terms) tend to report higher finance-growth nexus than when the dependent variable is specified in per-capita terms.<br><br>No change to the thesis was made but I hope this explanation clarifies the explanation of the effect. |
| **Chapter 2: Results**<br>One finding is that "…some aspects of data or methodology may be associated with publication bias, or small-sample and other biases" (page 38). Does this finding rather indicate that papers that did not addressed some issues properly (used worse approach) have been likely published in less-rated journals or even in not peer-reviewed journals, see also my point I-3. | The positive estimate indicates that publication bias is present once we correct for other factors by applying a multivariate meta-regression analysis (for example, controlling for the fact that the effect might be different across regions or time periods). This is, testing for publication bias using a funnel plot is in many areas of empirical research found not to be sufficient (e.g. see Stanley et al., 2010), which is the case if the effect sizes are not drawn from the same population (e.g. different regions).<br><br>As discussed in the paper, it is not fully clear what is the source of the large constant we get once we control for other study aspects (additionally to precision). The likely explanation is that some aspects of data or methodology may be associated with publication bias or small-sample biases. I did not include non-peer reviewed journals in the analysis. All the studies included in the meta-analysis were published in a Scopus-ranked journal. Also, only studies containing an empirical effect and studies reporting the estimate's precision were included (standard errors, t-statistics or p-values). Not having addressed some issues properly and the quality of research |

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| | conducted (proxied by the journal impact factor) has been accounted for elsewhere (i.e. including a relevant moderator variable in the MRA). Both moderator variables related to publication characteristics, namely, Journal impact factor and Publication year, are significant and positive. This finding suggests that studies published in journals with a higher impact factor report, on average, larger effects and that more recent studies report, on average, larger effects than earlier studies.<br><br>I have added the interpretation of the moderator variables that relate to publication characteristics to the revised version of the thesis. |
| **Chapter 3 and 4**: To better understand the novelty of Study II and III, I would appreciate to hear during the defence what is a contribution of this particular modelling, contrasting this research with modelling carried out elsewhere, in particular, in UCT's Energy Research Centre in Cape Town that has built several similar models, including TIMES, MESSAGE, LTMS-MARKAL, and TIAM that were mainly applied for RSA, and LEAP model that was used for SADC countries. While both the studies described nicely relevant energy markets and provided information about institutional background, I miss a review of models appropriate for this kind of assessment and particularly their applications in the concerned region. | The UCT Energy Research Centre uses planning models and has applied them to many different studies although to my knowledge the models have not been applied to the specific question of the cost of providing access in the SAPP region or the cost effects of more efficient regional electricity trade.<br><br>To the revised version of my thesis I have added a brief description of similar modelling frameworks to mine (MESSAGE, OSeMOSYS, TIMES and others) and also a brief discussion of model based analysis in the region. I note that ELMOD has quite a different focus given ELMOD is a static model that provides a detailed representation of the transmission network (DC load flows), whereas I relied on a planning model (i.e. including investment decisions) and with a simpler representation of transmission (transfer capacity).<br><br>I note that generally, the UCT ERC analyses issues related to South Africa although they do undertake studies for the region. See http://www.erc.uct.ac.za/outputs/2016-2020 for recent publications by staff.<br><br>While I have tried to provide a good overview of other modelling frameworks and their application, including the work undertaken by UCT Energy Research Centre, I do not provide an exhaustive review of power sector simulation models used globally precisely because the novelty / relevance of my work is in the application of the modelling framework to the region. For a comprehensive |

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| | overview of energy planning models, I refer the reader to Koltsaklis and Dagoumas (2018), who provide an overview of different generation expansion planning methodologies, with a focus on new challenges for expansion planning, and Ringkjøb et al. (2018) who present a thorough review of 75 modelling tools for analysing energy and electricity systems. For their implementation in the context of SSA, I refer the reader to Trotter et al. (2017), who categorise 306 articles on quantitative and qualitative electricity planning in SSA according to various dimensions. |
| **Chapter 3 and 4**: Which technologies are included in the model? Since average LCOE is 63-70 \$/MWh, it seems that renewable energy (RES), and in particular PVs, with lower LCOE at 39-50 \$/MWh, are not widely utilized. | Candidate generation projects from a range of technologies are available to the model:<br>• specific hydro, coal steam turbine (I also include generic coal projects as noted below) and geothermal projects; and<br>• generic projects for solar PV, PV with storage, CSP, onshore wind, coal steam turbine, CCGT, OCGT, and internal combustion engines (ICE).<br><br>You are correct that the LCOE of solar PV is well below the levelized incremental cost of access.<br><br>LCOE is an indicator of the average cost of electricity from a power station but it does not necessarily reflect the value of the power station to the system (a measure of the levelized <u>*avoided*</u> cost of energy and capacity is required to reflect the value to the system). In particular, solar PV without storage tends to produce its maximum output around noon whereas the daily demand peak in Africa generally occurs in the evening. Back-up generation capacity to solar PV would therefore be needed to serve the evening peak. This is reflected in the model through the hourly PV generation profile and the hourly demand profile, and also through the relatively low contribution of PV without storage to meeting capacity requirements.<br><br>In the revised submission, I have added to the results section of Chapter 3 a discussion around this to clarify the difference between LCOE and value to the system of a generation technology. |
| **Chapter 3**: How these costs associated with grid extension – with the | Thanks for this observation. |

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| connection and increase in its capacity – is incorporated into the model (additionally to just excluding a part of customers from the inter-connected energy system? If the grid costs are not a part of the model, how your results might change and how policy recommendation might be influenced? | Correct, we model the generation costs of the power system (and in chapter 4 we also model the costs of new interconnector transfer capacity) and do not include in the model the grid costs or connection costs of new customers. When calculating the cost of providing access in Chapter 3, we then make an off-model adjustment to costs to uplift them to reflect the magnitude of average grid costs in the power system. To do so, we follow Castellano et al. (2015) and EIA's reference case in 2018 (EIA, 2019a) and assume that generation costs represent about 60% of electricity system costs to derive the overall costs of supply. As such we derive grid costs of between 4.2 USc2018/kWh under the current rate of progress and 4.7 USc2018/kWh under the universal access target and high consumption scenario.<br><br>The objective of my analysis was to look at the incremental forward-looking wholesale costs of supply of achieving a given electricity access and how these costs could be affected by the degree of regional integration. The cost to connect and supply a household, including the costs of transmission and distribution, varies with distance to the main grid and some households will have higher or lower costs than suggested by our off-model adjustment. In the analysis, we considered that only 60% overall and 30% of the rural population currently with no access would gain access through the grid implying that the most distant households that are more expensive to connect and serve through the grid would rely on off-grid solutions.<br><br>I have clarified this point in the results section of Chapter 3, where I do the above off-model adjustment to derive the overall costs of on-grid supply. I have also clarified in Chapter 4 that I do not look at total costs but rather at wholesale costs (forward-looking generation + cross border interconnection costs) since those are the costs most affected by the possibility to trade (for example, see the beginning of the results section in Chapter 4). I also reiterated this point in the conclusion section in Chapter 4, that the incremental costs of providing access would also need to take account of the costs of expanding electricity networks within countries and last mile |

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| | connection costs. |
| **Chapter 3: Optimisation** - The system is optimised by minimising total generation costs, however, in a policy analysis "we isolate the cost of solely connecting new household customers are" (page 64). Increase in demand by one segment (i.e. newly connected dwellings) may however affect the system structure and hence may affect the total cost of electricity generation. For that reason, it would be better to also analyse a difference in total system costs for the baseline and for the counterfactual/policy scenarios. | This is a very good comment that reflects the thinking we had when designing the scenarios to compare when developing the analytical framework. As noted, the electricity sector is a system, and demand growth in one customer segment affects the overall structure of demand and overall system costs (that could either reduce or increase the incremental cost of supplying another customer segment).<br><br>The baseline scenario includes demand growth to the end of the planning horizon for non-residential demand and for existing connected residential customers. Each access scenario reflects the baseline demand *plus* the incremental demand of newly connected residential customers. The levelized incremental cost of access is then the difference between the two scenarios (access scenario less baseline scenario), which takes account of the effect of the newly connected household demand on overall system costs.<br><br>I have edited the methodology section in Chapter 3 to make this clear. |
| **Chapter 3 and 4: Time resolution** - Is the system optimised on annual basis, or are demand and production disaggregated in several periods, (months/seasons, hours, on/off-peak, etc.)? | The system is simultaneously optimised over each hour and year for the entire planning horizon. I say hour *<u>and</u>* year because some variables are annual decisions (generation commissioning or retirement) and some variables are hourly decisions (generation output, loss of load, lack of capacity, interconnector flow).<br><br>I have clarified this in the description of the optimisation model (Annex 4 where I discuss the representation of time in the model). |
| **Chapter 3 and 4: Capital costs** - I appreciate very detailed information about the costs, lifetime, and other technical data as presented in Appendix 4. Some capital costs seem to me high, however. For instance, the costs of PV are estimated at less than 900 EUR/MW for Europe, BloombergNET projects LCOE for PV at 39-50 $/MWh (2018). The main data source for the thesis is SAPP Pool Pan (2017) that were then | It is a very good observation that solar PV costs are changing rapidly over time. For this reason, while for most technologies we relied on the SAPP Pool Plan 2017, for solar PV capex costs we took the IRENA global average capex cost for 2018 and apply an 8.09% per commissioning year cost reduction based on *IRENA, The Power to Change: Solar and Wind Cost Reduction Potential to 2025*. I have added this explanation to the description of CAPEX data in Annex 4. |

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| adjusted by inflation. I recommend to check for which period this data are coming from and whether the learning-cost effect may exceed at least inflation. I also recommend to update the data, possibly in further research. | There is wide variation between the costs of solar PV projects globally, partly driven by the solar resource and partly driven by other factors such as project WACC, development expenses and procurement process (tender or auction v. negotiated agreement). For example, *IRENA Power Generation Costs in 2019* provides a global range of solar LCOE. While the average levelised cost of electricity (LCOE) of renewable energy technologies also declined in SSA, these costs remain substantially above those that we see in Europe or Latin America as results of auctions. For example, for South Africa the average LCOE for utility-scale solar PV stood at 90 \$/MWh and for onshore wind at 70 \$/MWh in 2018 (IEA, 2019a, p.444). Therefore, I am comfortable using PV costs in the model that are higher than those than in Europe. Therefore, I did not make any change to the analysis for this point.<br><br>Given the rapid recent development in solar PV and battery storage costs (which helps the power system to capture the benefits of solar PV), I agree that this sort of analysis needs to be updated in future to take account of the latest cost information (I note that the same holds for fuel prices). |
| **Chapter 3**: Representation of results - RSA consumption represents about ¾ of total demand in SSA region. It would be useful to look closely to the results by country, or at least excluding RSA, because the result for RSA may dominate the overall result. | This is a very insightful point and we did consider providing results by country. However, we have not done so for several reasons. The power systems of the SAPP region are interconnected, and therefore it is difficult to isolate the effects of increasing access in a single country. For example, we cannot simply use the incremental levelized cost for the region and multiply that by the level of consumption of the newly connected customers each year for a country.<br><br>One approach to estimate the cost of access by country would be to hold everything in the model constant and change access for a single country and re-run the model. The status of all other countries (e.g. all other countries are set to the base case or to the 100% access scenario) when exploring the country in question. The results for the country in question will be affected by the status of every other country. Therefore, a good picture of the costs of access in each country would require many model runs and a simplified |

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| | version of the model may be more appropriate for this country specific analysis. Given the computational requirements we chose not to do this country specific analysis – I noted in the conclusions of Chapter 3 that this would be an interesting extension to the work in future that would require significant run time but could use an unchanged model structure.<br><br>An alternative approach would be to run the simulation model as we have done and to place a value on hourly imports and exports for each country. However, because this hourly value could be anywhere between the hourly system margin cost in the exporting country and the hourly system marginal cost in the importing country (the value is a "negotiated" value), we decided that this approach would be arbitrary in assigning costs and benefits to individual countries. An interesting extension to the work (and a topic for a potentially third energy paper using the same optimisation model) would be to explore the individual costs for each country under different scenarios for the "negotiated" value put on exports/imports.<br><br>I have not made a change for this in the thesis but it is a good area for expanding the model and analysis in the future, and hence I have added this area of potential future research to the conclusions section in Chapter 3. I have also described a possible extension in the conclusions section of Chapter 4 to calculate the costs and benefits of trade for each country. |
| **Chapter 3: Minor: Assumption on aggregate demand** - "Under the current rate of progress (S1), which reflects the average rate at which new household customers were connected in the period from 2013 to 2018, the incremental consumption stemming from new connections (both on-grid and off-grid) is estimated to increase overall customer demand only marginally, by about 8.0 TWh by 2030" (page 62), that is from 385 TWh to 392 TWh in 2030. But demand in 2018 was 288 TWh (page 59), so what is the difference between 385 TWh and 288 TWh? | Figure 4 provides the current level of on-grid sent-out demand of 332 TWh out of which 288 TWh was billed in that year with the rest representing T&D losses. The level of on-grid sent-out demand of existing (i.e. already connected) customers is forecast to increase from 332 TWh in 2018 to 385 TWh in 2030.<br><br>That is, the 385 TWh refers to sent-out demand in 2030 of existing customers, while the 288 TWh is the amount of energy billed in 2018 in the region by the utilities.<br><br>Please refer to Annex 6 for details on the current and future level of on-grid demand. Table 8 provides details on the incremental on-grid and |

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| | off-grid demand stemming from new connections by 2030 under the different access scenarios. |
| **Chapter 4: Model structure**: Is trade realistic option for some regions? Have you considered natural barriers, like highlands in Lesotho (borded by RSA), or protected areas like Krueger National park on the border between RSA and Mozambique? | I fully agree that the ability to develop new transmission is limited by natural features in addition to capex. Thorough feasibility studies as well as environmental and social impact analysis need to be undertaken before any decision on new interconnection is made, as well as a cost benefit analysis (CBA) that would try to quantify the overall costs and benefits of a project (including e.g. emission costs, costs of relocation of people if that cannot be avoided, impact on habitats etc.).<br><br>The interconnector investment options that we consider in the model are those set out in the SAPP Pool Plan (2017). In other words, we use identified projects although the projects may well be at inception stage before detailed environmental and social studies have been carried out. I expect that some of the identified projects could face insurmountable barriers to development and conversely other projects or alternative routes for identified projects could be identified.<br><br>In the revised version of my dissertation thesis, I included a discussion around this point (please see the supply side data section in Chapter 4). |
| **Chapter 4: Optimisation**: How the interconnector transfer capacity is considered in the model objective function? | Interconnector decisions (build and flow decisions) affect the objective function directly only though interconnector capex and indirectly through several mechanisms, including energy losses as power flows through the interconnector (increasing generation operating costs), by interconnector flows allowing cheap generation output to displace expensive generation output or to displace loss of load, and through interconnector import capacity helping to meet the capacity requirement for the importing country (potentially reducing generation capex).<br><br>I have added this explanation to Annex 5 of the revised version of the dissertation thesis because it will help the reader to understand the effects of interconnectors and the model's decision making around interconnectors. |
| Editing and formatting is needed, see | Thanks for having noted this. I have corrected for |

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| for instance, missing legend in Figure 7, Study III. | this in the revised submission. |
| **4. Comments and suggestions made by the Committee during the pre-defence** | **My replies to the comments and suggestions made by the Committee** |
| Using a different discount rate and its impact on results. | In my analysis I relied on a 6% real discount rate, which is also the real discount rate used in SAPP Pool Plan (2017) and the social discount rate commonly used by the World Bank in their work in SSA.<br><br>I agree that it would be interesting to explore the effect of different discount rates. In particular, some countries may have a different discount rate, discount rates may change over time and developers may use a higher discount rate to reflect their average cost of capital. The choice of discount rate is important because it helps determine the optimal type of generation developed to meet demand, with a low discount rate favouring projects with higher up-front capital costs, e.g. hydro and solar PV, and a high discount rate favouring projects with lower up-front costs such as gas fired power plants. Therefore, in the revised version of my thesis I included a sensitivity where I apply a higher discount rate of 10% (please refer to the results section of Chapter 4). With a higher discount rate, less hydro, solar PV and wind generation is developed than with the social discount rate of 6%, and more gas, coal and oil fired generation is developed, in line with expectations. |
| Figure 13 – some flows show zero, what does that mean? | I have added a footnote to Figure 13, clarifying the interpretation of the flows. While Figure 13 shows interconnectors for all of the possible country pairs currently considered for development in the SAPP region, a number of these are not developed according to the least-cost optimisation model. This is represented by a zero flow in both directions of the interconnector on the chart. I note that for some interconnectors, only unidirectional flow takes place, which is represented by a zero flow in one direction of the interconnector. |
| Endogeneity issue among some studies: not controlling for endogeneity in the model specification investigating the relationship between financial development and economic growth. | Well noted, thank you for the comment. I have noted new trends in the field of meta-analysis in the revised version of the thesis. I also discuss this point in relation to comments made by Mgr. Milan Ščasný PhD. |

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| Trend is to set aside studies that really are bad and to derive results from studies that are good – actually do both the full set and a sub-set of good studies. Some tools in meta-analysis help with this but that is a second order remedy. First order remedy is not to use rubbish studies. It would be worth adding recent developments in the field of meta-analysis to the revised version of the thesis. | |
| Robustness of results on the costs of providing access. | Several sensitivity analyses have been included in this revised version of the thesis. Please refer to 'Sensitivity analysis' in the results section under Chapter 4. Chapter 3 also elaborates on sensitivity of results with respect to demand (I consider a high demand scenario). |
| Chapter 2: We cannot conclude on causal effects from cross country studies and therefore nowadays these are not taken seriously. Do not describe it as casual effects but rather a relationship. | Well noted. This has been corrected in the revised version of the thesis. |
| Chapter 3: Wave of papers that show in SSA there is low willingness to pay, demand falls sharply with price perhaps because of the need for complementary investments. Recent paper from U.C. Berkeley do not square well with claims in the thesis. Papers are sceptical about role of electrification. | Thanks for this comment. I have included a discussion of the work by Lee et al. (2016, 2019, 2020) from U.C. Berkeley in the introductory chapter of the thesis.<br><br>The researchers from U.C. Berkeley asked a very important, albeit a different question compared to my research. Specifically, they conducted experimental research in which they elicited WTP for electricity access to the main grid by offering four different levels of connection charges to households in rural Kenya. They found that the households' WTP is below the costs of providing access, suggesting that electrification could result in a welfare loss. The authors themselves, however, say that demand for access and WTP may be low because of market failures, including credit constraints or a lack of knowledge about the long-term benefits of electricity.<br><br>It would be interesting to see how the findings of their experiment would have changed, had credit constraints been lifted by asking households to pay for example a \$30 initial deposit and a monthly payment of \$1.55 for the next 10 years, assuming a social discount rate of 6%, instead of a one-off payment of \$171, which was the official |

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| | connection cost achieved with the Last Mile Connectivity Project in Kenya.<br><br>Furthermore, a recent study by Do and Jacoby (2020) showed that asking households to pay a full connection fee ex-ante might lead to socially undesirable outcomes when households are forming habits and when households cannot know the lifetime benefits of access.<br><br>That being said, I do agree that the question asked by the researchers from U.C. Berkeley is very pertinent especially in view of the different technological solutions available to provide electricity access. As I discuss in my research, the most cost-effective solution will be different for each area or settlement and will depend on many characteristics, such as distance from the main grid, demographics, size and density of population clusters, terrain, consumption patterns of end users, and the relative costs of different technologies and their future development. In my research I consider that only about 60% of those newly connected will be connected to the main grid (and only 30% of rural households newly gaining access are assumed to be connected to the main grid).<br><br>With respect to the benefits of access, I also fully agree that in order for access to be meaningful important barriers have to be overcome. This includes for households the ability to access appliances needed for electricity use. While in my work I did not assess the benefits of electrification (I looked only at the wholesale generation costs of scaling up electricity access through the main grid), I note that there is a rich body of research evidence of the positive benefits of electrification as well as its importance for other SDGs. I provide several references to these studies throughout the thesis. |