Final Report

Economic and Climate Impact of Power Investments across Six African Countries

Côte d'Ivoire, Kenya, Mozambique, Senegal, South Africa and Zambia

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Disclaimer

The views expressed in this report are those of the evaluators. They do not represent those of British International Investment or of any of the individuals and organisations referred to in the report.

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Foreword

Reliable electricity is essential for economic progress, but it remains a challenge in sub-Saharan Africa, where 75% of firms face outages. At BII, investing in power is an important part of what we do, with 24% of our portfolio in the power sector. Fossil fuels are major contributors to global carbon emissions and climate change, which is why we invest in low-carbon alternatives. Our climate change strategy[1] and 2022–26 technical strategy[2] ensure that our investments align with economic development pathways consistent with net zero emissions and climate resilience.

This study, by independent evaluators from Itad and Steward Redqueen as part of the FCDO–BII Evaluations and Learning Programme, uses detailed modelling to assess how various power generation technologies support our ambitions to boost reliable power and accelerate the green transition in different country contexts. It models how adding 1 megawatt of power to the grid using different technologies affects gross domestic product (GDP) and greenhouse gas (GHG) emissions in six African countries.

There are several valuable insights from the research:

- **Investing in technology to accelerate the transition to reliable, clean power is essential.** Sustained economic growth powered by clean energy requires renewable energy that is more affordable and storage systems which can readily dispatch power to address outages. The impact of battery energy storage systems for solar power at peak times in South Africa highlights the need to reduce the cost of these technologies. For us, this underlines the importance of equity and concessional finance to strengthen the supply of bankable projects and demonstrate the business case for increased investment. For example, we have backed Scatec's development of solar and battery storage facilities in South Africa to contribute 1.1 gigawatt hours (GWh) of dispatchable power to the grid,[3] and we have backed similar projects through Globeleq in Mozambique.[4]
- **Investments that diversify the energy grid are crucial for strengthening climate resilience,** particularly in countries reliant on hydropower and vulnerable to climate change-related weather events such as drought. In Kenya, the study found that diversifying away from hydropower, for example through other renewable energy sources, enhances resilience in dry years.
- **Investments in power transmission can be more cost-effective for reducing outages and GHG emissions than investments in power generation.** Investing in electricity networks is also key to diversifying energy sources and increasing the sustainability and economic efficiency of the power system. The Kenya case study found that, with large regional variations in outages, investment in transmission reduced outages and emissions more cost-efficiently than investments in generation. We invest in transmission through Gridworks,[5] which provides equity finance to develop projects in transmission and distribution (T&D), and off-grid electricity across Africa, for example the Amari Power Transmission project in Uganda to improve electricity supply to industrial users.[6]
- **Investments to improve economic efficiency and reduce peak demand could offset the need for investment in generating capacity.** Although not directly addressed in this study, the results suggest that investing in system efficiencies (such as digitalisation of the grid) and demand-side management (such as smart meters) can reduce demand at peak times and improve the overall economic efficiency of the power system.

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[1] BII (n.d.) 'Climate Change Strategy'.

[2] BII (n.d.) 'Productive, Sustainable and Inclusive Investment'.

[3] BII (2022) 'British International Investment joins Standard Bank and H1 Holdings to back Scatec's South Africa renewable energy technology project'.

[4] BII (2023) 'Globeleq begins commercial operations at Cuamba solar and battery storage plant in Mozambique'.

[5] BII (2019) 'CDC launches new company, Gridworks, to invest in electricity networks across Africa'.

[6] Gridworks (2025) 'Amari Power Transmission'. https://gridworkspartners.com/amari-power-transmission/

As with all models and underlying datasets, there are limitations which need to be considered when interpreting the results. Critically, in addition to the limitations identified in the report, the model only considers supply-side interventions and does not adequately assess the impact of investing in T&D and regional interconnectors. Further analysis of this wider set of technological options for demand-side management and other system improvements would enhance understanding of their impact.

Similarly, the modelling does not consider key economic and financial risks, such as transition risk (the risk of long-term infrastructure assets becoming stranded as countries transition to a low-carbon economy), dependency on fossil fuel imports, and volatile fossil fuel prices. It assesses short-term reliability of the power system but not the optimal addition of generation technologies to meet growing electricity demand over time.

The analysis sometimes identifies investment in fossil fuels as the most effective investment. However, this is based on historical cost data for generation and storage technologies and does not include social benefits of technological advances in renewable power and storage systems, which have only recently started to become cost-competitive with fossil fuels as a source of dispatchable power. With continued technological advances, the costs of battery and other storage technologies are likely to decline further in the relatively near term.

In our view, when considering the broader range of risks associated with fossil fuels, potential opportunities for power systems, and the imperative to support countries transition to net zero, renewable power systems that improve reliability (including storage technologies and improved T&D systems) are the right choice. This is also consistent with our fossil fuel policy,[7] whereby we only invest in lower-emitting fossil fuel technologies when the investment aligns with a country's development pathway to net zero emissions by 2050 and contributes towards the power system's net zero transition.

Overall, the report provides useful, practical analysis of the interactions between differing generation technology options. It highlights that more reliable power systems can increase GDP by many times the investment's capital cost in a just a few years, suggesting that the right investments can pay off quickly from a societal perspective.

Our role as an investor in new and emerging power generation technologies, as well as in T&D infrastructure, is critical for reliable power supply on the African continent. Our ability to be involved at an early stage of project development through our equity investments sets us apart from our peers and is something we will continue to build on. We hope that the findings of this report will be useful to other investors and stakeholders considering the range of issues that are relevant to their power sector investments and financing approaches.

Holger Rothenbusch
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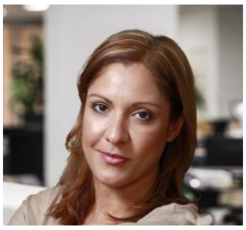

Amal-Lee Amin
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[7] BII (2020) Our Fossil Fuel Policy. https://assets.bii.co.uk/wp-content/uploads/2022/03/22173318/Fossil-Fuel-Policy-1.pdf

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List of acronyms

ADB	Asian Development Bank
ARENE	Energy Regulatory Authority
BESS	Battery Energy Storage System
BII	British International Investment
CCGT	Combined-Cycle Gas Turbine
CDM	Clean Development Mechanism
CFA	West African Franc
CIE	Compagnie Ivoirienne d'Electricité
CO_2	Carbon Dioxide
CRSE	Commission de Régulation du Secteur de l'Electricité
CSP	Concentrated Solar Power
CTS	Cost-to-Serve
EAF	Energy Availability Factor
EBRD	European Bank for Reconstruction and Development
EDM	Electricidade de Moçambique
EIA	U.S. Energy Information Administration
EIB	European Investment Bank
ERB	Energy Regulation Board
FCDO	Foreign, Commonwealth & Development Office
FTE	Full-Time Equivalent
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GIS	Geographic Information System
GTAP	Global Trade Analysis Project
GW	Gigawatt(s)
GWh	Gigawatt Hour(s)
HFO	Heavy Fuel Oil
IEA	International Energy Agency
ILO	International Labour Organization
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
KenGen	Kenya Electricity Generating Company
KETRACO	Kenya Electricity Transmission Company

KPLC	Kenya Power and Lighting Company
KSh	Kenyan Shilling
kV	Kilovolt
kWh	Kilowatt Hour
LCOE	Levelized Cost of Electricity
MW	Megawatt(s)
MW_{AC}	Megawatt(s) (Alternating Current)
MWh	Megawatt Hour
MZN	Mozambican Metical
NERSA	National Energy Regulator of South Africa
NASA	National Aeronautics and Space Administration
NGFS	Network for Greening the Financial System
O&M	Operations and Maintenance
OCGT	Open-Cycle Gas Turbine
POWER	Prediction of Worldwide Energy Resources
PPA	Power Purchase Agreement
RMIPPPP	Risk Mitigation IPP Procurement Programme
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
Solar PV	Solar Photovoltaic
SRMC	Short-Run Marginal Cost
T&D	Transmission and Distribution
tCO_2e	Tonne(s) of Carbon Dioxide Equivalent
tCO_2e/y	Tonne(s) of Carbon Dioxide Equivalent per Year
TWh	Terawatt Hour(s)
US	United States of America
VoLL	Value of Lost Load
VRE	Variable Renewable Energy
WBES	World Bank Enterprise Surveys
WIEGO	Women in Informal Employment: Globalizing and Organizing
ZAR	South African Rand
ZESCO	Zambia Electricity Supply Corporation Limited
ZMW	Zambian Kwacha

Executive summary

This report presents the findings from an ongoing in-depth study of impact in British International Investment's (BII's) infrastructure portfolio. The evaluation of BII's infrastructure portfolio is commissioned by the Foreign, Commonwealth & Development Office (FCDO) as part of the FCDO–BII Evaluation & Learning Programme. This multi-year evaluation is undertaken by Itad and Steward Redqueen. This report on the development and climate impact of power systems in Africa is one of the in-depth evaluations that follows on from the Portfolio Review of BII's entire infrastructure portfolio.[8]

A sufficient and reliable supply of electricity is imperative for economic development – no modern economy has ever developed without it. The absence of reliable power is one of the main impediments to economic development in many African countries. For Africa's economies to modernise and become more productive, investments in the power sector are indispensable. The growing population further underscores the need for investments in the power sector – generation, and transmission and distribution (T&D).

The International Energy Agency estimates that Africa needs to invest $25 billion annually by 2030 in its power systems to ensure modern energy for all. The energy path that Africa will follow, specifically the mix of renewable and fossil fuel generation, holds great significance for its development and for global greenhouse gas (GHG) emissions. By and large, the lack of centralised fossil fuel infrastructure and the abundant potential for renewable energy provide an opportunity for African countries to develop a less carbon-intensive energy system. However, there are trade-offs between reliability, low GHG emissions and the cost of power production. With existing technologies, the least-cost power system does not usually equate to the lowest-emissions power system.

This report describes a methodology used to analyse the development and climate impacts and cost-effectiveness of power technologies in six countries in Africa: Côte d'Ivoire, Kenya, Mozambique, Senegal, South Africa and Zambia. The methodology determines the marginal impact from increased generation capacity on power outages, cost of power, GHG emissions, gross domestic product (GDP) and employment. These marginal impacts depend on (i) the

[8] Steward Redqueen & Itad (2022) Evaluating the Impact of British International Investment's Infrastructure Portfolio.

generation technology, (ii) the power system dynamics of the country, and (iii) the response of private sector firms. In each country, the generation technologies considered in this report are the ones that are already installed. The solar plus battery storage technology was only analysed in South Africa. The report adds to the existing literature by combining (i) a physical model of power supply and dispatch that mimics the behaviour of grid operators with (ii) an economic model of how the private sector responds to changes in power reliability and costs.

A model of the power sector captures the time-varying interplay of power supply and demand in a country. By matching hourly supply and demand throughout the year, the model produces estimates of (i) the electric energy, in megawatt hours (MWh), lost due to outages, (ii) the weighted average generation cost per kilowatt hour (kWh) generated, and (iii) the weighted average GHG emissions per kWh of energy produced. By inserting additional capacity of different generation technologies, the marginal impact on these three variables can be inferred. The model can be extended to include transmission, which is useful when there are bottlenecks that cause regional outages. Because this requires a more detailed analysis of the transmission network in a country, this has only been performed for Kenya.

Private sector firms respond to changes in the frequency and duration of outages and the cost of power, which results in changes in value added (or GDP) and accompanying changes in employment. First, we estimate the Value of Lost Load (VoLL – a monetary value that represents society's willingness to pay to avoid a kWh lost due to power outage) in a country using five different methods. Multiplication of VoLL by the reduction of the lost load due to outages from the power model results in the GDP effect due to the reduction in outages. Second, by analysing how the aggregate production of private sector firms changes in response to increased power consumption and how power consumption responds to a change in the cost of power, we derive the effect of cheaper or more expensive power on GDP contribution. The change in formal employment is subsequently derived from total GDP contribution using employment intensities in the formal sector.

With the total GDP and GHG impact per additional megawatt (MW) generation capacity determined, we analyse the climate–development nexus from an investor's perspective. For this, we express the GDP and GHG impact per million dollars, using the different capital costs of the various technologies. By depicting the GDP and GHG impact per million dollars, different climate–development frontiers can be defined that depend solely on the carbon price chosen by the investor.

The main takeaways of the study are as follows:

Identical power interventions in different countries can have rather different GDP and GHG impacts. The economic impact of adding generation capacity depends largely on its ability to reduce outages, as opposed to its ability to reduce the price consumers pay for power. For example, open-cycle gas turbine (OCGT) in South Africa comes out as the investment with the highest economic impact, despite it having the highest costs of operation. For GHG emissions, the impact depends on the frequency of outages and the emissions of the last power plant in the merit order. In countries with frequent outages (e.g. Côte d'Ivoire), more of the additional renewable energy capacity goes towards reducing outages, and thus cannot displace thermal plants at the end of the merit order. In countries where the last power plant in the merit order has high emissions (e.g. Zambia and Senegal), even relatively low-emitting carbon technologies such as combined-cycle gas turbine (CCGT) reduce GHG emissions.

The results highlight the importance of cheap, easily dispatchable power in countries where outages occur frequently. Ensuring that the power is dispatchable (and resolves outages) is key; the impact of solar power in Kenya is constrained because most outages occur after sunset, but in South Africa affordable solar[9] photovoltaics (solar PV) stands out as one of the most effective interventions. Although solar PV is very efficient in decarbonising the grid, thermal power plants (heavy fuel oil (HFO), OCGT, CCGT) are much more effective in reducing outages after dark. Rather than concluding that thermal plants are an optimal investment choice, we would advocate for finding more climate-friendly dispatchable solutions, such as the conversion of HFO plants to OCGT, or cost-effective hybrid solutions such as solar PV/battery energy storage system (BESS) or solar PV/gas. A good example of this is BII's investment in the Kenhardt PV/BESS power plant in South Africa, although much depends on the (still high but decreasing) capital costs of such plants. Moreover, there exist other considerations when deciding what to invest in, including the need to avoid reliance on imported fossil fuels given the volatility of global fuel prices, the impact on forex reserves, (international) investment appetite and the long-term climate-related socioeconomic impacts of climate change.

In general, there are trade-offs between reliability, cost and GHG emissions of different power technologies, and the optimal choice depends on the carbon price and the power system dynamics of each country. Investors should consider using a shadow carbon price to systematically compare the climate and development impacts of different types of power investments across different geographies. The framework suggested in this report can be used to evaluate climate and development trade-offs within and between independent power producer investments.

Certain technologies break with the traditional trade-off between development and climate impacts. Barriers still exist that prevent the widespread adoption of these technologies. For example, geothermal is efficient at reducing both outages and GHG emissions, but only a few locations have the right conditions for it. Adding battery storage to a solar PV plant also decreases both power outages and GHG emissions, yet high capital costs may still be a constraining factor for certain projects. As capital costs are expected to decrease in the coming years, solar combined with storage is expected to replace the role currently played by fossil fuel-based peaker plants.

Given the heightened volatility in (hydro) power supply availability across Africa, diversification of power systems and greater reliance on regional power pools to effectively manage fluctuations are important. Power systems must be able to cope with increased volatility in power supply availability. For example, climate change-induced droughts may greatly decrease the availability of hydropower, whereas reliance on fossil fuel imports may create fuel shortages because of geopolitical factors or other supply chain constraints. GDP and GHG impacts may therefore vary considerably across certain years and speak to the necessity for countries to diversify their power sector, rely on regional interconnections to improve geographical resilience, and build up capacity to prepare for the future. Diversification may be impeded by non-cost-reflective tariffs in certain markets. In Zambia for example, underpricing of hydropower may distort investment decisions, leading to negative modelled GDP impact, which may disincentivise investment into new renewable power plants.

[9] Solar energy includes multiple power technologies, such as solar photovoltaics and concentrated solar power, and combinations such as solar photovoltaics with batteries or energy storage. Solar power is differentiated from specific solar technologies throughout this report.

Investments in transmission can offer a more cost-effective solution to reducing outages and driving environmental and socioeconomic impact compared to investments in power generation. In many African countries, most outages are caused by T&D bottlenecks and/or failures. Regional and international transmission investments can ensure that existing power generation infrastructure is used more fully and can improve resilience across systems. We conducted an analysis of Kenya and found that investments in transmission are the most cost-effective way to create a positive environmental and socioeconomic impact, outshining investments in power generation. Given the high incidence of transmission constraints, we suspect that these findings could be applicable on a broader scale.

The methodology described in this report provides a pragmatic approach to assessing development and climate impacts. We construct a modelled counterfactual because no direct observations on the impact of an individual power plant can be made, given that there is no 'line of sight' to the end user. The advantage of the power sector is that the aggregate system dynamics can be observed, allowing for model results to be validated. We show that the model reproduces observed outages, electricity cost and GHG emissions. This allows the model to be used in various ways. For example, the model can assess the expected (ex ante) impact of an investment, and it can also be used to retrospectively (ex post) assess the impact of an investment by modelling the situation at the time of the investment. Key model inputs, including weather patterns, exchange rate fluctuations and the cost of fossil fuels, can also be altered in order to understand how the power system responds to this.

In contrast to the power model results, which can be checked against observable data, the private sector response is largely unobservable, and hence the socioeconomic model results cannot be verified against observable data. Although we think the approach taken is often used and defensible, it could be improved in three ways. First, the inclusion of firm datasets larger than the World Bank Enterprise Surveys would allow for more granular results. However, many countries do not have these datasets. Second, the results focus on how investments would improve current supply conditions in terms of reliability, costs and GHG emissions and less on what supply is needed to satisfy growing demands. The proposed methodology is, however, perfectly capable of incorporating forecasted supply and demand. Third, the inclusion of long-run effects such as firm investment and firm entry would ideally be included. Although collecting reliable data on this would be cumbersome, the small amount of academic research that has been performed in this area points to long-run results that may be double the short-run impacts included in this report. A forthcoming report on the commercial and industrial power investments of BII will look more closely at how more reliable and/or cheaper power affects the operational and investment decisions of individual firms.

1. Introduction

Power generation is at the forefront of developmental agendas, owing to its pivotal role in underpinning modern economies and driving climate change mitigation and adaptation efforts. Independent power producer (IPP) investments constitute about 60% of British International Investment's (BII's) infrastructure portfolio of $2.3 billion. The Evidence Review of the BII Infrastructure Evaluation10 found three distinct ways to study grid-scale power generation:

- impact on power outages (frequency and duration) and subsequently on firm productivity and economic output;
- impact on the cost of power production and the extent to which this subsequently changes end user power tariffs and economic output; and
- the nexus of development impact and climate neutrality and optimal power investments under different circumstances.

These three topics will be researched in detail throughout this study.

1.1. Study focus

Given the breadth of the BII IPP portfolio in terms of size, generation technologies and countries, we need a comprehensive methodology to assess the developmental and climatic effects of different investments. The methodology developed in this report aims to analyse the development and climate impacts of IPP investments. Because the impact of individual investments depends on the broader system in which they take place, this study analyses impacts through a national power system lens. This systems analysis is developed for six countries: Côte d'Ivoire, Kenya, Mozambique, Senegal, South Africa and Zambia. These countries were selected based on their substantial differences in power sector structure, energy mix, supply and demand balance, private sector composition and strategic relevance for BII.

The investment technologies chosen in the different country scenarios in this report mirror the currently installed power fleet and do not necessarily reflect BII's strategic priorities. BII focuses on investments in countries where additional power is needed and invests primarily in renewables and energy storage (where viable). Regarding non-renewables, BII published a new climate change strategy in July 2020 which set out how to achieve net zero emissions across its portfolio by 2050. This excludes new investment in most fossil fuel subsectors, with just a few exceptions remaining. For example, investments in gas-fired power stations are only pursued if

[10] Steward Redqueen & Itad (2022) Evaluating the Impact of British International Investment's Infrastructure Portfolio.

they fulfil the requirements of BII's new guidance on natural gas power plants, which requires an investment to be transitionary to net zero by demonstrating alignment with a country's pathway to net zero emissions by 2050.

1.2. Learning objectives

The primary goal of this multi-country comparative analysis is to provide insights for BII's investment staff and for development impact and climate professionals in BII and beyond. The three key learning objectives are:

1. Investigate how different types of IPP investments generate development impact based on the existing structure of the power supply sector and the specific demands of the private sector.
2. Quantify trade-offs between development impact and (mitigation of) greenhouse gas (GHG) emissions.
3. Identify 'just net zero scenarios' and 'investment roadmaps' that optimise development and climate impact under different supply and demand conditions and private sector needs.

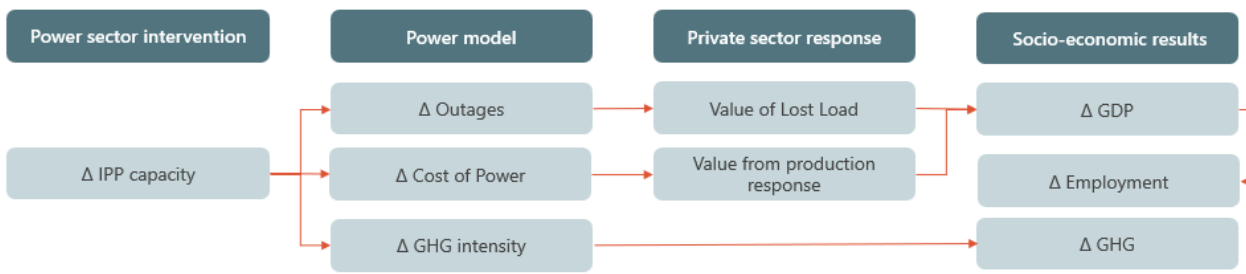
1.3. Structure of the report

Section 2 describes the power sector in Africa and the six individual countries. Section 3 presents a model of the power sector to analyse changes resulting from additional power generation capacity. Section 0 describes how the private sector responds to these changes, and Section 5 summarises the socioeconomic results for the six countries. Section 6 synthesises the results across generation technologies and countries and assesses the (investment) implications by looking at the capital effectiveness of the many options to achieve economic development and mitigate GHG emissions.

1.4. Methodology

Figure 1 presents a high-level overview of the methodology and key outputs of the approach. The model's starting point is an intervention in the power sector. The methodology considers the effect of increasing IPP capacity by 1 megawatt (MW) nameplate capacity[11] of different technologies in the power system. The unit of 1 MW is chosen to accurately compare the impacts of different technologies, but the model allows for capital additions of any size.[12]

Figure 1. Overview of methodology



[11] Nameplate capacity is a classification, written in MW, used by authorities to register how much power a station generates.

[12] When adding a large amount of generation capacity, sensitivities can be skewed because of partial utilisation of that capacity. A small addition allows for the analysis of sensitivities at the margin. For the analysis of a 40 MW solar plant in which BII has invested, see Annex 2 on Kenya.

We model the power system by combining power supply and demand data to understand how the power system responds to interventions in the system. In this analysis, we focus on three impact channels: (i) changes in outages; (ii) changes in the cost of power; and (iii) changes in the GHG intensity of the power system. The power model can be extended further. Three extensions described in this report are the inclusion of transmission, the addition of battery storage systems, and the analysis of using realistic hydropower tariffs in countries where it is used as base load power.

The impact of additional IPP capacity on the rest of the economy depends on the response of the private sector to the changes in the power system. Our methodology considers two main impact channels. First, an outage represents a loss of economic value for firms, which is expressed as the Value of Lost Load (VoLL), a monetary value that represents society's willingness to pay to avoid a power outage; a reduction of outages (or lost load) therefore creates economic value. Second, firms change their production in response to a change in power prices.

The model's three key socioeconomic results are gross domestic product (GDP), measured in dollars ($); employment (number of jobs); and GHG emissions, measured in tonnes of carbon dioxide equivalent per year (tCO_2e/y).

1.5. Limitations

The model's main limitation concerns the treatment of the private sector response to changes in the power system.

First, the analysis does not allow for the quantification of sector-specific value added and employment results. This reflects the fact that VoLL is typically thought of as an 'economy-wide' measure that amalgamates firms across sectors. Moreover, specification of VoLL at the individual firm or economic sector level requires detailed data which is not normally available in emerging markets.

Second, the private sector response in this report is a so-called short-term response, which assumes an unchanged production structure within firms. Quantification of the long-term response, which reflects investment in productivity enhancements and the entry of new firms, among others, is more speculative because of data paucity. It is generally accepted, however, that the long-term response is larger than the short-term response.

Third, although the model includes some consideration of imported power, it models power systems at the national level and does not account for potential regional effects.

1.6. Audience

This report is aimed primarily at BII investment staff and at development impact and climate professionals in BII and in the Foreign, Commonwealth & Development Office (FCDO). Given the importance of and interest in the power sector's development and climate impact, the study may be of interest to the wider development impact and climate mitigation community.

2. The power sector in Africa

2.1. Overview

Across the African continent, 600 million people (51% of the population) lack access to electricity – a stark contrast to the global average of 9%.[13] Although there has been some relative improvement, the number of individuals without electricity in sub-Saharan Africa continues to rise, owing to rapid population growth. Notably, annual electricity consumption per person in the region is estimated to be less than that of a standard United States of America (US) household fridge (3% of the average consumption of a US citizen) and has not increased materially over more than three decades.[14] There are significant disparities in access to electricity across the continent, ranging from universal access in countries such as Morocco, Algeria and Egypt to as low as 7% in South Sudan. The limited electricity access and consumption in Africa mirrors the power generation gap of the continent.

According to the IEA, Africa needs to add more than 1,000 gigawatts (GW) of installed capacity by 2040 to meet its growing demand, which is roughly five times the current level of 230 GW. To achieve the region's energy supply and climate targets, energy investments will have to more than double from today's $90 billion by 2030, with almost two-thirds of this going towards clean energy. However, there are significant obstacles to financing renewable energy projects. Africa receives a mere 2% of global renewable energy investments,[15] compared to a global population share of almost 20%.

As shown in Figure 2, natural gas dominates the electricity mix of Africa, constituting 42% of the total electricity generated, concentrated principally in Northern Africa, followed by coal at 28%, fuelled primarily by South Africa's abundant coal resources, and hydropower at 17%.[16] Solar, wind and geothermal energy collectively contribute 6% to electricity generation.

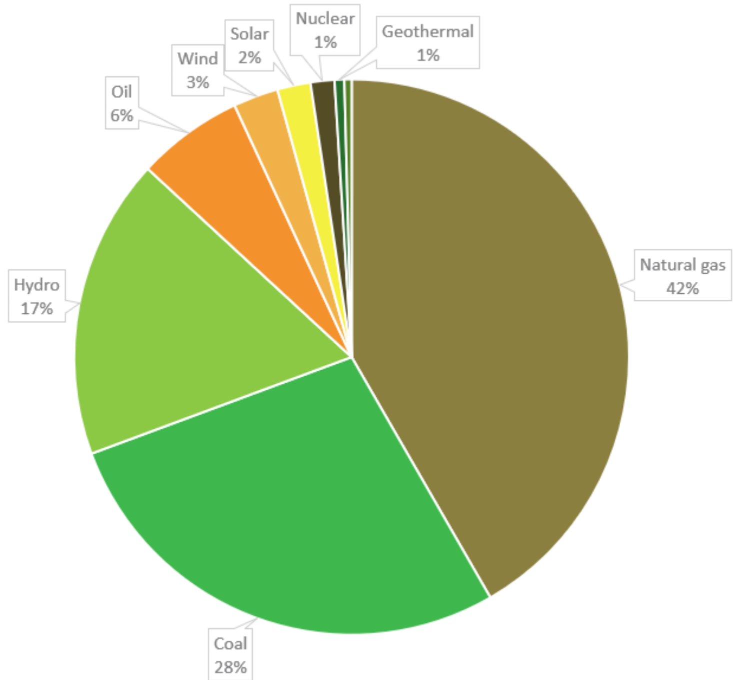
[13] Source: World Bank.

[14] Sources: World Bank, International Energy Agency (IEA).

[15] Source: IEA (2023) Africa Energy Outlook 2022.

[16] Source: IEA.

Figure 2. Electricity generation by technology type in Africa (Source: IEA, 2021)



Some African nations rely heavily on domestic fossil fuel resources, while others are vulnerable to volatile international markets because of dependence on imported fuels. Reducing dependence on fossil fuels, which currently contribute to over three-quarters of electricity generation in Africa, is crucial for cutting carbon dioxide (CO_2) emissions and enhancing energy security. At the same time, Africa's population is set to grow rapidly, making up one-fifth of the world's population by 2030, and its economy is expected to grow concomitantly. The IEA forecasts, for the period 2024–26, an average annual growth in total electricity demand of 4% in the region – more than twice the mean growth rate observed over 2015–23.

Compared to the rest of the world, Africa is different in that it does not have a substantial fleet of dispatchable generators that can be replaced with renewables. Instead, it must build the energy infrastructure from a low starting point. The typical African grid energy transition is therefore envisioned as 'vertical', because total output needs to rise rapidly. In contrast, mature economies experience a 'horizontal' energy transition, relying on existing 'firm' resources to handle intermittency from increased reliance on renewables, while integrating alternatives such as energy storage over time.[17] As will be shown, this overall picture masks substantial heterogeneity between countries. This heterogeneity cannot be 'traded away', because of the lack of interconnections between countries. Only 8% of Africa's electricity is traded across borders,[18] compared to 44% in Europe.

Africa holds immense potential for renewable energy, benefiting from favourable climatic conditions for solar, wind, hydropower and geothermal sources. The swift adoption of renewables will enable Africa to avoid the pitfalls of heavy reliance on fossil fuels. However, many African countries currently cannot meet their energy needs from renewables alone. Models of the electricity system transition in Africa, considering the imperative of achieving

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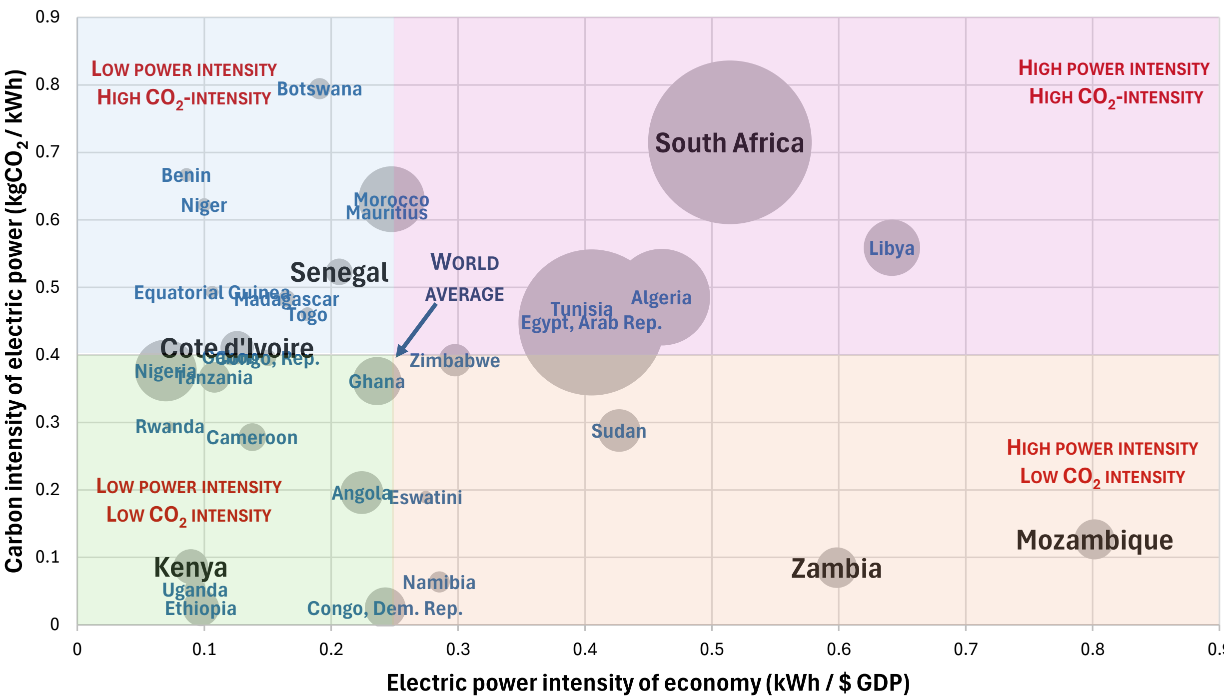
[17] CDC (2021) Insight: Decarbonising Africa's Grid Electricity Generation.

[18] Most of the electricity trade occurs in the Southern African Power Pool (12 countries, with the largest trade from Mozambique to South Africa), West African Power Pool (14 countries), Eastern African Power Pool (11 countries, with Ethiopia the largest exporter) and Central African Power Pool (9 countries).

carbon neutrality by 2050 and rapidly expanding electricity generation for economic development, foresee the need for investments in a mix of generation technologies over the medium term. In an ambitious climate change mitigation scenario,[19] annual power capacity additions in Africa between 2030 and 2050 amount to 24 GW of solar, 20 GW of wind and 18 GW of gas. But these aggregate numbers mask the considerable variations between countries regarding the need to add power capacity and the best suitable type of generation technology.

Figure 3 captures this heterogeneity in terms of electric power intensity, measured in kilowatt hours per dollar of GDP (kWh/$ GDP) and the CO_2 emission intensity of electric power (measured in kg CO_2/kWh). Countries vary widely on both dimensions, reflecting different levels of economic development, energy access, resource endowments and policy choices. The partitioning into four quadrants, based on the world averages of both indicators, makes it easy to profile the different countries. For example, Kenya has a low power intensity and a low CO_2 intensity. Although the power sector is much greener than the world average, one can convincingly argue that the low electricity consumption is a hurdle for GDP growth. South Africa, in contrast, has an economy which is much more power-intensive than the world average and, in fact, all richer nations. This indicates that it has not effectively translated electricity consumption into economic growth. The high CO_2 intensity of its coal-dominated power generation underscores the country's widely recognised need to decarbonise.

Figure 3. Electric power intensity of economy and CO_2 intensity[20] of power for African countries. Bubble size indicates total power consumption in gigawatt hours (GWh). The six countries in this report are highlighted.



These differences illustrate that there is no 'one size fits all' solution for achieving power-enabled economic growth and decarbonising the power sector. Countries must tailor power generation plans to their specific contexts and needs. For the six countries highlighted in Figure

[19] Van der Zwaan, B., Kober, T., Dalla Longa, F. and Van der Laan, A. (2018) An integrated assessment of pathways for low-carbon development in Africa. *Energy Policy* 117.

[20] The emission intensity of hydropower-dependent countries (notably Kenya and Zambia) can differ between dry and wet years.

3, this report will analyse the GDP and CO_2 impacts of different IPP interventions, and Table 1 summarises some high-level economic and power consumption statistics. For each of them, a brief introduction of the power sector is provided in the next section.

Table 1. Characteristics of power systems of countries in this study

	Côte d'Ivoire	Kenya	Mozambique	Senegal	South Africa	Zambia
Population (million people)	27.5	53.0	32.1	16.8	59.42	19.5
GDP ($ billion)	71.8	110.3	18.4	27.7	419.0	22.1
GDP/capita ($)	2,486	2,070	504	1,634	7,074	1,135
Total electricity consumption (GWh)	9,040	9,806	12,959	5,687	216,010	13,222
Access to electricity (% of population)	71%	77%	32%	68%	89%	47%
Electricity consumption per capita (kWh)	329	185	404	337	3,637	679

2.2. The power systems of the study countries

2.2.1. Côte d'Ivoire

In terms of installed capacity, Côte d'Ivoire's power system consists mainly of thermal (60%) and hydroelectric (40%) power. In terms of power production, thermal plants are responsible for 91% of the country's energy output. The Compagnie Ivoirienne d'Electricité (CIE, owned by the private company Eranove) contributes approximately 45% to the country's power production. It also holds the concession for electricity transmission and distribution (T&D). Tariff-financed CI-Energies oversees the sector's development and infrastructure projects.

Private entities also play a significant role, especially in power generation, including multinational corporations and IPPs contributing to the country's energy capacity through hydroelectric and thermal (gas and oil-fired) plants.

The government's strategy focuses on expanding access to electricity, increasing the share of renewables in the energy mix and strengthening regional energy cooperation. Renewable plants such as solar and biomass are already under construction. Tariffs are regulated by the government, with the aim to balance affordability for consumers with the need to attract investment into the sector. Tariffs are largely reflective of the total cost of generation and T&D.

2.2.2. Kenya

Kenya's power generation capacity consists of geothermal plants (29%), hydropower plants (27%), thermal heavy fuel oil (HFO) plants (23%) and variable renewable sources of energy (20%). As a reliable source of power, geothermal plants meet most of the country's energy requirements (48%), followed by reservoir and run-of-the-river hydropower plants (22%) and the wind and solar plants that comprise the variable renewable energy (VRE) fleet (19%). Thermal HFO plants are largely used as peaker plants. However, the country's energy mix changes drastically based on climate, because drought reduces hydropower capacity and requires further dependency on thermal HFO plants, increasing both GHG emissions and costs.

The power system is structured between three public entities: the Kenya Power and Lighting Company (KPLC), the Kenya Electricity Transmission Company (KETRACO) and the Kenya Electricity Generating Company (KenGen). KETRACO builds and operates the transmission network and is responsible for setting the merit order as the operator of the National Control Centre. KPLC is responsible for the distribution and sale of electricity.

KenGen's fleet of geothermal, hydropower, wind and thermal HFO plants provides 60% of the installed capacity and 70% of the produced power. IPPs play a key role in the country's energy capacity, with a mix of geothermal, hydropower, solar, wind and thermal HFO plants. In the last decade, Kenya's power capacity has kept pace with the growth in demand. Most of the growth in installed capacity has come from IPPs, and the entire solar capacity of the country is privately held. Tariffs in the country are largely cost-reflective, owing to a wholesale power market and regular reviews of retail tariffs.

The government's focus is on increasing investment in capacity while keeping tariffs low – an added challenge because the Kenyan shilling (KSh) has weakened against the US dollar, which increases the cost of the imported oil used in HFO plants. The government's strategy relies on further exploiting geothermal sites, building international transmission lines to increase imports of electricity from Ethiopia's hydropower capacity, and further developing the country's solar and wind capacity.

2.2.3. Mozambique

Mozambique's energy system is characterised by a diversified mix of hydropower (57%), thermal energy (37%) and renewable energy (5%). In terms of renewable energy, Mozambique produces solar energy (3%), as well as biomass energy (2%) through sugar companies operating in the country. The country's reliance on hydropower exposes it to climatic variability, with droughts impacting water availability and consequently reducing hydropower output. During such periods, Mozambique resorts to thermal power generation to meet electricity demand.

Mozambique's energy strategy focuses on diversifying the energy mix to enhance resilience and sustainability. This includes the continued development of renewable energy sources such as solar and wind, alongside investments in natural gas infrastructure for power generation. Additionally, efforts are under way to improve T&D lines, because the reliability, affordability and quality of services is a growing concern; if these are compromised, so is broader access to electricity across the country.

The power sector in Mozambique is overseen by several key entities, including Electricidade de Moçambique (EDM), responsible for power generation and T&D. EDM operates and maintains the national grid, ensuring a reliable electricity supply across the country.

The country's power system operates through two key public entities: (i) EDM, which is responsible for power generation and T&D; and (ii) the Energy Regulatory Authority (ARENE), which regulates electricity, gas and petroleum.

Despite electricity tariffs in Mozambique being high, they are not cost-reflective, which effectively means that the government subsidises EDM. This impacts the country's ability to invest in reliable infrastructure.

2.2.4. Senegal

Power generation is relatively dispersed in Senegal. Senelec, Senegal's government-owned utility, contributes only about 28% to the country's total power production, with the rest supplied by various IPPs. Senegal's power grid relies heavily on thermal energy, accounting for 79% of production, followed by hydropower (8%), wind (7%) and solar (6%), meaning it has a relatively high GHG intensity in terms of its power system.

Senegal's national power strategy is geared towards reducing reliance on imported fuels. This involves a strategic shift towards gas-to-power conversion, capitalising on recently discovered offshore gas fields, and a significant boost in renewable energy capacity.

The Senegalese government subsidises Senelec to maintain electricity tariffs well below cost recovery levels. Every quarter, the electricity regulator, Commission de Régulation du Secteur de l'Electricité (CRSE), sets the level of actual tariffs and calculates full cost-recovery tariffs. When actual tariffs are below cost recovery levels, the regulator is required by law to either adjust the tariffs or to compensate Senelec through budget subsidies. Tariffs were below cost recovery by 23% in 2021, and this percentage is expected to reach 32% in 2022.

2.2.5. South Africa

South Africa's power system is controlled by state-owned utility Eskom, which generates approximately 88% of all electricity consumed, with a large number of small-scale IPPs providing the remainder. The energy mix is dominated by coal (73% of total generation), of which South Africa has an abundant supply, followed by open-cycle gas turbine (OCGT) (6%), hydropower (6%), renewables (5%) and nuclear energy (3%).

In recent times the South African power system has grappled with unprecedented levels of load shedding. This challenge is attributed to supply shortages stemming from mismanagement issues at Eskom and an ageing fleet of coal plants.

South Africa stands out as the most industrialised nation in Africa, resulting in a significant energy dependency of its economy. This translates into a notably high-power intensity in terms of its economy. Owing to its heavy reliance on coal, South Africa also has the power system with the highest GHG intensity per unit of energy produced of all the countries in the study.

The National Energy Regulator of South Africa (NERSA) regulates the electricity industry and determines Eskom's tariffs. Eskom does not provide details of how various components make up its price, but tariffs are largely cost-reflective.[21] However, a study by Lazard (2019)[22] concluded that Eskom's prices are not cost-reflective and are low compared to international standards.

2.2.6. Zambia

Zambia's power system is managed primarily by the state-owned utility ZESCO (Zambia Electricity Supply Corporation Limited). ZESCO generates the majority of Zambia's electricity through state-owned hydropower plants, with a small portion coming from various IPPs.

The energy mix is dominated by hydropower, which accounts for 88% of total generation capacity. Abundant hydropower resources account for about 65% of total generation, harnessed through two large-scale hydroelectric power stations, the Kariba Dam and the Kafue Gorge Dam, from the Zambezi River and its tributaries. In recent years, Zambia has also built solar power plants, which make up less than 1% of its total power capacity.

The power system faces challenges, including occasional supply shortages and reliability issues, particularly during dry and drought periods. To compensate for lower levels of hydropower generation, ZESCO institutes a deliberate load shedding policy based on assessments of water levels in the Kafue and Zambezi basins.

The Energy Regulation Board (ERB) regulates and oversees ZESCO's tariff setting. Historically, tariffs in Zambia have not been fully cost-reflective. Underinvestment in the power sector has been partly because of these below-cost tariffs.[23] The Zambian treasury allocates about $1.3 billion per year to fuel and electricity subsidies. These low costs are much to the benefit of the mining sector, which consumes over 50% of Zambia's power and is central to the government's economic growth strategy. ZESCO's financial stability, however, hinders this growth, because the current tariff-setting scenario in Zambia has not been able to follow the rise of operational costs[24] and ZESCO continues to owe international lenders over $1.76 billion. Outstanding loans to ZESCO from overseas banks contribute 5.5% of Zambia's total debt.[25] Simultaneously, lack of pricing parity between end user tariff and cost from IPPs and imports has continued to increase over the years, leading to greater ZESCO debt to IPPs.

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[21] World Bank Group (2024) 'South Africa'. https://rise.esmap.org/country/south-africa

[22] Lazard, Report Extract 'Electricity Prices in South Africa are Low by International Standards', Lazard report submitted to Eskom, 2019.

[23] PMRC (2020) 'Blog – Zambia's Power Sector Reforms: "The Light at the end of the tunnel"'. https://pmrczambia.com/blog-zambias-power-sector-reforms-the-light-at-the-end-of-the-tunnel/

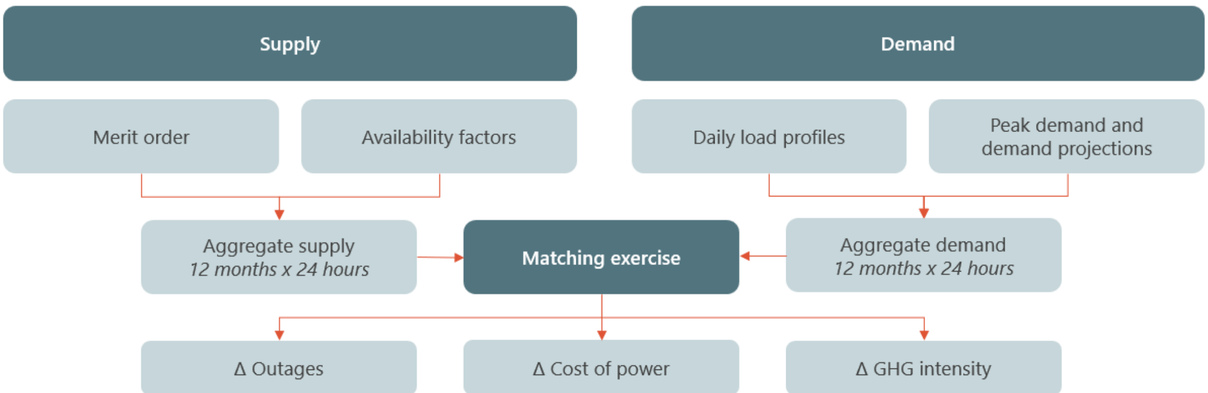
[24] Energy Market and Regulatory Consultants Limited, prepared for Energy Regulation Board, supported by the African Development Bank (2021) 'Zambia Electricity Cost of Service Study'.

[25] Mafa, C. and Mathiason, N. (2022) 'Zambia's sovereign debt crisis: How foreign creditors have all the power over country's economic recovery'. https://www.financeuncovered.org/stories/zambia-sovereign-debt-crisis-zesco-economic-recovery

3. Modelling of the power sector

We have developed a model that replicates the dynamics of the power system of each country, enabling a comprehensive assessment of investments in the power sector. Because the model captures the essence of how the power system behaves, it can estimate the effect of power investments on outages, cost of power and GHG emissions. The model comprises two distinct components – the power supply and the power demand modules – which are interlinked to generate the outcome measures. Figure 4 summarises the methodology for the power model. This modelling framework is used to evaluate the effects of additional investments in the power supply. To quantify these impacts, we employ a comparative approach, contrasting the introduction of 1 MW of power capacity against the baseline scenario.

Figure 4. Overview of the power model



3.1. Power supply

The power supply component of the model contains all power generation plants that operate within the country, including their cost levels and GHG intensity. The power supply analysis relies on two core elements: the merit order and supply availability factors.

3.1.1. Merit order

The merit order is the fundamental tool in the modelling approach, guiding the determination of which power plants are active at any point in time. The merit order graphs the cost (in $/kWh) against capacity (in MW) in order of plant utilisation. The merit order considers multiple factors, such as price, dispatchability, GHG emissions and strategic considerations. When prioritising price as a key factor, the merit order ensures that power sources with the lowest marginal costs are brought online first to meet the demand, and those with higher marginal costs are activated later. This method, known as economic dispatch, minimises the overall electricity production costs.

However, the merit order curve reflects the reality of operating a regional or national grid. In a theoretical scenario, power plants can be arranged in ascending order based on cost, but grid operators must also consider factors such as dispatchability and apply policies that target different power technologies. As such, the merit order is adjusted based on factors such as the dispatchability and insights gained from desk research about the power system of each country.

In the merit order we distinguish between base load, peak load and intermediate load (Figure 5). Base load plants are characterised by low total costs per kWh, high capital intensity and long start-up times, and usually output a steady level of power (within the limits of availability). Intermittent renewable energy sources, such as wind and solar, operate at the same level of the merit order because they are not dispatchable, owing to their fluctuating nature. Peak load plants have higher costs per kWh, low capital intensity and fast start-up times, and are more easily 'controlled' (e.g. dammed hydroelectricity), which makes them easier to dispatch. Peak load plants are usually only active in times of great power demand. Intermediate load plants are positioned between base load and peak load, and therefore they occupy a position in the middle of the merit order.

To construct the merit order, we calculate the short-run marginal cost (SRMC) of each power plant by combining fuel expenses and variable operations and maintenance (O&M) costs, expressed in dollars per megawatt hour ($/MWh). Subsequently, we arrange all power plants in ascending order based on these calculated costs, plotting the cost per unit of energy against the available capacity. Where needed, we adjust the merit order to reflect other factors, such as the dispatchability of energy and prevailing dispatch policy.

Figure 5. Different types of power plant (Kenya)

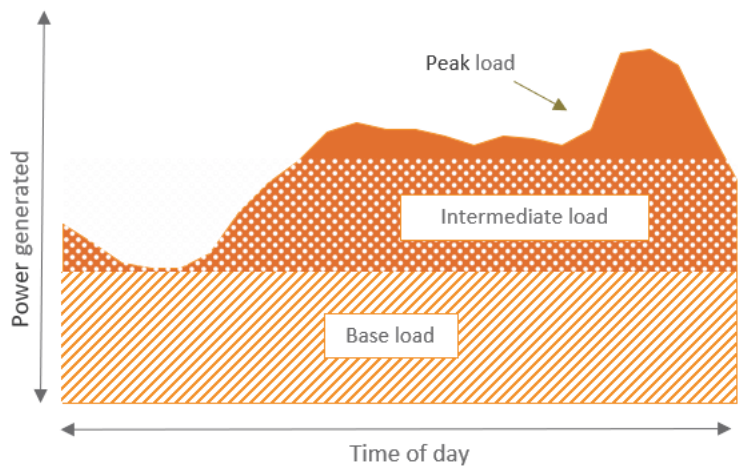
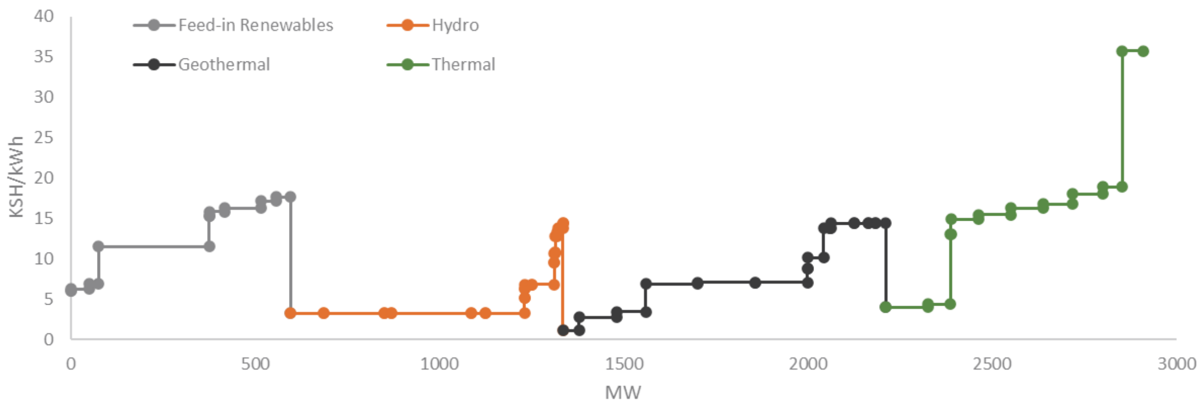


Figure 6 presents the modelled merit order for Kenya. To encourage the development of renewables, the Kenyan utility commits to buying energy for a predetermined feed-in tariff for non-dispatchable renewable technologies such as solar and wind. These renewables are integrated into the grid first. Geothermal energy is prioritised ahead of hydropower, despite having higher average costs. This decision is influenced by the reduced availability of hydropower and the need to conserve water resources during dry seasons and/or years. Depending on the level of demand, geothermal and parts of the hydropower capacity serve as the base load power sources. Thermal (mostly HFO) power plants are utilised to accommodate peak load demands. Despite their higher SRMC, their advantage lies in their quick dispatchability owing to their quick start-up times and low capital intensity in comparison to base load plants.

Figure 6. Kenya's merit order



To construct the SRMC for the merit order, we compile cost data from various sources, each offering different levels of granularity. Ideally, we abstract plant-level cost data for both fixed and variable costs from financial reports and power purchase agreements (PPAs) of the utility. Variable costs include the tariffs paid per unit of energy produced and fuel costs.[26] Peaking thermal plants often charge the utility a yearly capacity charge, which can be seen as the fee to provide the option for dispatchable power at any moment. Because the merit order reflects the moment-to-moment decision to bring power plants online, these yearly capacity charges are considered fixed costs.

In cases where plant-level data is unavailable, we rely on data broken down by technology type. In such instances, we allocate the average cost per technology to all plants. When granular data cannot be sourced from the utility, we make informed assumptions based on findings from other reputable studies, including those by the International Renewable Energy Agency (IRENA), the IEA, and academic research. More details on the sources used for each of the country-level studies can be found in the country-specific annexes.

In addition to the above, the following data points are gathered for each power plant:

- **GHG emissions.** Ideally, we rely on plant-level data on annual GHG emissions. In cases where detailed GHG data on a plant level is unavailable, we rely on data concerning fuel inputs and thermal efficiency, country-level data on GHG emissions by technology type, and assumptions based on available studies.
- **Commission and decommission dates.** The inclusion of (expected) commission and decommission dates allows the model to simulate past and future scenarios for the country's power system.

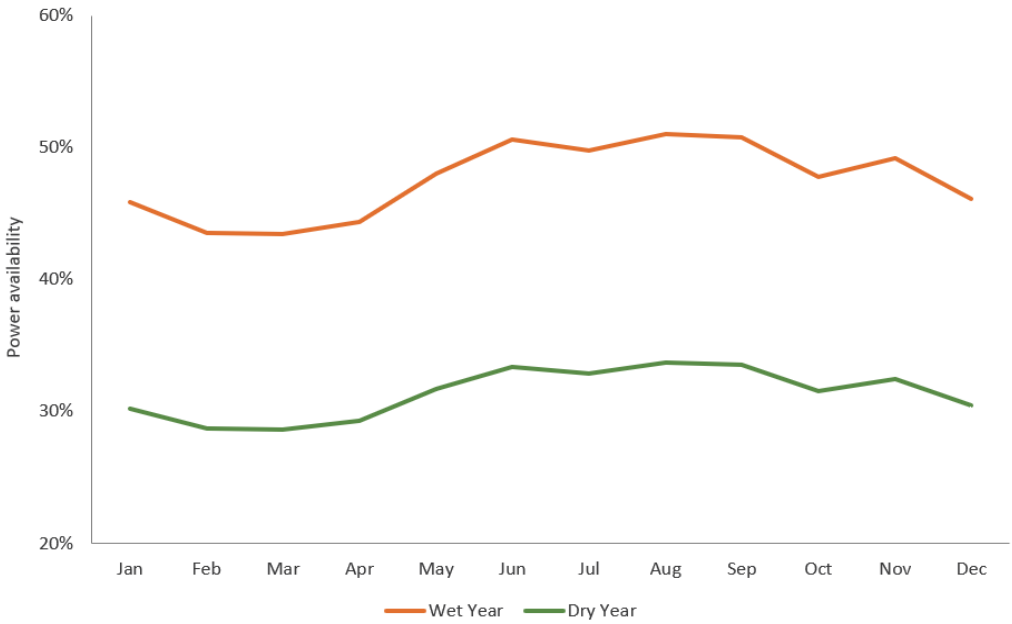
[26] Changes in fuel cost owing to foreign exchange rates that affect fuel cost in local currency terms can be accommodated in the model. This is especially relevant because most PPAs are stated in dollar terms.

- **Location.** In model extensions, we consider the transmission network and the geographic location of each power plant.

3.1.2. Availability factors

In addition to the merit order, availability factors of plants are another critical input in modelling power supply. The availability of power supply varies significantly throughout the day and across different seasons, depending on the type of technology. For example, solar is diurnal, and hydropower power is strongly seasonal but can vary substantially from year to year. Figure 7 shows the variability in hydropower supply in Kenya across the year. The availability of hydropower exhibits clear seasonality, with limited availability during the dry months from December to March. The difference between wet and dry years is substantially larger than the seasonal variation, with hydropower availability dropping by around 30% between the average wet and dry year. Both scenarios have been analysed (see Annex 2), although in this part of the report we present results from a typical wet year.

Figure 7. Hydropower availability in Kenya for wet and dry years



The approach to determine power availability varies per type of technology. Where possible, we utilise availability factors specific to individual plants. In cases where this information is unavailable, availability is based on averages per technology type used.

The approach per technology type is as follows:

- **Thermal and geothermal plants:** we rely on plant-specific data where available. In cases where such data is lacking, we assume an availability of 95%, reflecting near-permanent availability except for planned maintenance periods and incidental faults.
- **Hydropower plants:** we utilise data from the utility to determine monthly variations in available supply. For countries that experience droughts, there are large variations between dry and wet years – these are also modelled. We deploy data from the African Hydropower Atlas[27] if detailed data is not available at the utility level.

[27] IRENA (2021) African Renewable Electricity Profiles for Energy Modelling Database: Hydropower.

- **Solar plants:** we rely on detailed data at the utility level, if possible. Alternatively, we rely on meteorological data from the Global Solar Atlas to determine the average daily supply curve for each month.
- **Wind plants:** we rely on detailed data at the utility level if possible. Alternatively, we rely on meteorological data from the National Aeronautics and Space Administration (NASA) power database to determine the average daily supply curve for each month.

The power supply from individual power plants is aggregated to determine the total power production during each hour of an average day for each month. We also account for T&D losses by comparing aggregate data on total power production with total power sales. We assume that T&D losses are distributed evenly across the year and that no differences exist on a per-plant level, so that we can scale down total supply by the difference between total production and sales for each time period to arrive at the total power production available for consumers.

3.1.3. Aggregate supply

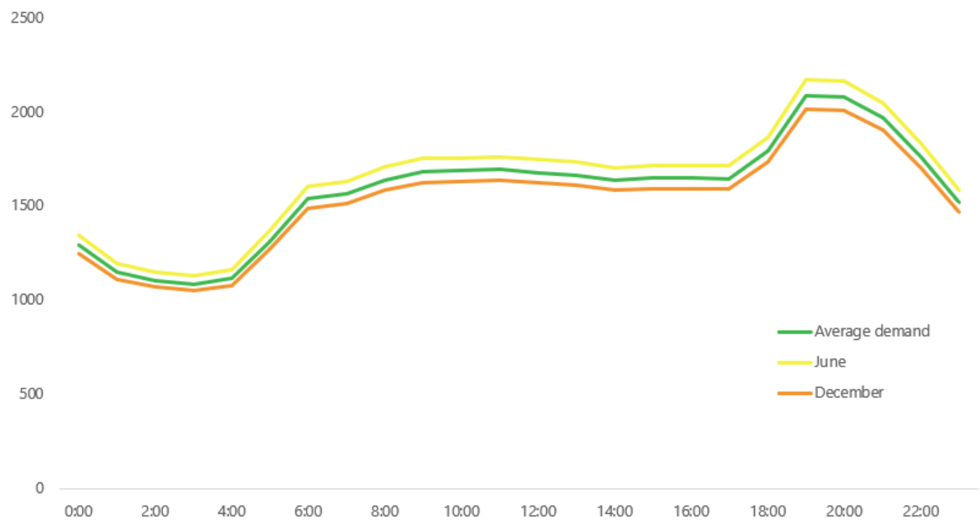
By combining the information derived from the merit order, availability factors and T&D losses, we determine the amount of power available for consumers, the order in which power plants are dispatched, the generation costs and GHG emissions. The result is a 24-hour by 12-month table of power supply for an average day in each month.

3.2. Power demand

3.2.1. Daily demand profiles

The demand for electrical power exhibits fluctuations over the course of a day, characterised by lower consumption during nighttime hours and higher demand during the early evening, coinciding with people's return from work. The overall daily demand pattern is encapsulated in the load curve, which is illustrated for Kenya in Figure 8 for June (high demand), December (low demand) and on average. All load curves show a similar pattern, with a gradual increase in the early hours and a sharp peak in demand between 7:00pm and 9:00pm. Peak demand is approximately 7% lower in December than in June. Seasonal variation of electricity demand, owing to variation of day length and temperature, is quite small in Kenya because it is on the equator.

Figure 8. Kenya's daily load profile in June, December and on average



3.2.2. Demand and demand projections

Demand patterns are obtained from the national utility. When only the average daily demand curve is provided, we scale it using monthly peak load data provided by the utility and preserve the diurnal pattern.

As an extension, the model may also incorporate projections of power demand growth, where available, to facilitate the modelling of future energy demand.

3.2.3. Reserve margins

Utilities set a target reserve margin to ensure that the available power supply safely exceeds the power demand. This target margin can vary and is specified in the development plans set by utilities. The model counts an outage when the available power supply cannot meet the sum of power demand and target reserve margin. The parameter that defines the target reserve margin can be adjusted to model different scenarios. In our baseline scenarios, we consider a 10% reserve margin for all markets.[28]

3.2.4. Aggregate demand

The outcome of the power demand analysis is presented in the form of a 24-hour by 12-month table, which details the power demand (in MW) for an average day of each month throughout the year. For some of the markets, this data is published by the utility or energy regulator. For other markets, we combine the load curve, monthly peak demand and total power demand to estimate the average hourly power demand in each month. The country-specific annexes describe the approach deployed for each market in detail.

3.3. Supply and demand matching

The matching exercise combines the developed power supply and demand models. For each hour, the model uses the merit order to determine the 'market-clearing' plant – the last plant that needs to generate power to meet the demand in the system. The model then has the information to understand how much of the available supply is used.

Once this is determined, the model can calculate three key impact metrics: (i) the level and frequency of outages, when supply cannot meet demand; (ii) the cost of generating power, based on the cost data and the dispatched power; and (iii) the GHG emissions and intensity of the power system.

With this, the power model can be used to estimate the effect of an increase of generation capacity on three impact channels: (i) a change in outages; (ii) a change in the cost of power; and (iii) a change in the GHG intensity of the power system. For each of these impact channels, we compare the results obtained in the baseline model with the addition of IPP investment of 1 MW of nameplate capacity.

To match the power system model to real life, we compare key outcome variables of the model – including total power produced, total outages and generation costs – to actual data. If there is a substantial deviation between the model and real data, we adjust our key assumptions, including

[28] This is likely a more conservative estimate. Typically, sizeable systems uphold a reserve margin of no less than 15%, and smaller systems often exceed this percentage.

plant availability and demand patterns. A comparison of model outputs and actual data can be found in the annex for each country study.

Figure 9. Kenya's load duration curve, supply duration curves, and reserve margin

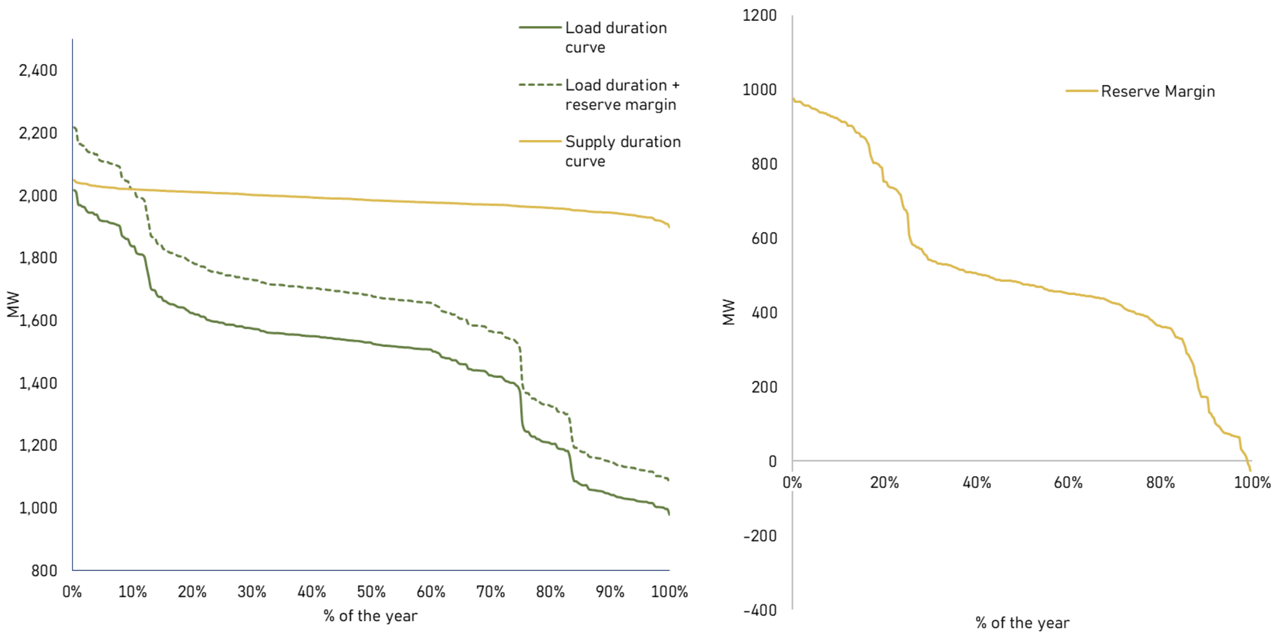


Figure 9 shows Kenya's load duration and supply duration curves and its resultant reserve margin. These curves order supply and demand data in descending order of magnitude and therefore give an indication of how well the power supply can keep up with demand. In Kenya, the load duration curve lies below the supply duration curve. When factoring in the utility's target reserve margin, the load lies above the supply for roughly 10% of the year. This provides a strong indication of outage frequency in Kenya. However, it is important to note that this does not represent the complete outage duration, because the data lacks time sequencing.

To provide a more accurate reflection of outage frequency, we look at the resultant reserve margin graph across the year. This charts the difference in MW between demand (including transmission losses) and available supply throughout the year. As can be seen, Kenya has outages owing to a lack of generation for 1% of the year. But at reserve margins less than 200 MW, outages become increasingly likely because of volatility of supply and demand.

3.4. Power model outputs

3.4.1. Δ outages

In the model, outages occur when there is insufficient supply to meet demand (including the target reserve margin). We can express outages in terms of total lost load (expressed in MWh) and length of total outages (expressed in hours). Both indicators only express outages that are caused by supply shortages, and not those caused by T&D failures or other issues. Studies indicate that in market-based power markets there may be a link between power prices and outages as well, because wholesale power demand may fall when procurement costs rise.[29]

[29] Jha, A., Preonas, L. and Burlig, F. (2022) 'Blackouts: The role of India's wholesale electricity market'. NBER Working Paper 29610.

However, in this study we will consider the change in outages and change in price as independent from each other.

Ideally, the model predicts outages at roughly the correct time of day and season. We calibrate the results based on hourly outage data from the utility. Alternatively, we rely on high-level data points such as the total size and duration of outages and total power produced.

The following indicators are used against which to measure and compare outages:

- total lost load, which is the total power demand that cannot be met because of disruptions in power supply (expressed in MWh);
- total length of outages owing to disruptions in power supply (expressed in hours); and
- when available from the network operator, we use technical reliability measures such as the System Average Interruption Duration Index (SAIDI), which is the average outage duration for each customer served, and the System Average Interruption Frequency Index (SAIFI), which is the average number of interruptions that a customer would experience.[30]

To assess the change in outages, we compare the results of the baseline model to that of adding a hypothetical plant of 1 MW of a given technology. This very small number is deliberate because we aim to analyse the incremental impact of each technology – the impact at the margin. The per MW impact of, for example, a 100 MW capacity addition may be less, when the system did not require an addition of that size. However, the model can be used to analyse real-world additions as well. For example, in Annex 2 we analyse the impact of the 40 MW Malindi power plant.

To determine the availability of this additional plant, we assume the average availability of existing plants for renewables and 90% availability for all thermal technologies. We then complement those availability figures with additional literature research if specified.

The study only considers technologies that are feasible and realistic to add to the energy mix of a country, considering power investment plans and the current energy mix. For example, Kenya does not have any plans to build coal-fired power plants; therefore, coal power is not considered for Kenya. South Africa does not have the right conditions for geothermal power. We also note that these technologies do not necessarily reflect BII's investment priorities, because BII's fossil fuel policy excludes new investment in most fossil fuel subsectors, with just a few exceptions remaining.

Table 2 shows the effects of adding 1 MW capacity to reduce total outages for each of the technologies considered for the respective country studies. The reductions in outages are highest in South Africa, which has experienced unprecedented levels of load shedding in recent years. Because the results in Côte d'Ivoire are based on data from 2021, when a breakdown of one of the main power plants caused excessive outages, the outage reductions (combined-cycle gas turbine (CCGT)) are high as well. Generally, investments in dispatchable power plants (solar photovoltaics (solar PV) & storage, CCGT, HFO, OCGT) cause the highest reduction in outages for most countries, because they can quickly be dispatched whenever the need arises. Solar PV has the lowest effect on outages, owing to unavailability around peak demand hours.

[30] Although each utility collects this data, most often it is not publicly available. The World Bank Enterprise Surveys (WBES) also have information on the frequency and average duration of outages, which can be used in lieu of utility reliability data.

Table 2. Effects of adding 1 MW capacity on total annual outages (MWh)

1 MW capacity	Côte d'Ivoire	Kenya	Mozambique	Senegal	South Africa	Zambia
Total outages in system	166,724	23,783	1,196	0[31]	1,775,000	25,146
Solar PV	-121	0	0	0	-524	-19
Solar PV & storage					-1,905	
Concentrated solar power (CSP)					-1,274	
Wind		-156	-18	0	-770	-72
Hydropower	-136	-196	-22	0	-778	-187
Geothermal		-464	-48			-290
CCGT	-1,268		-55	0		-345
OCGT/HFO		-522		0	-1,853	-345
Coal					-1,561	-345

3.4.2. Δ cost of power ($/kWh)

To assess changes in the cost of power, we rely on the merit order and cost data of individual power plants. By considering the power demand during a specific hour, the matching exercise determines the market-clearing power plant within our model. The market-clearing plant represents the final source of power dispatched to meet demand.

Once the operational power plants have been identified, the model calculates the cumulative expenses incurred during power dispatch. These time-specific costs are then aggregated on an annual basis, and we integrate fixed costs to calculate the total expenses associated with power generation. Furthermore, the model incorporates T&D costs of the utility, to convert power generation costs into the total cost of power faced by the end user. We calibrate and validate our findings by comparing generation costs and the cost of power with data points provided by the utility.

To gain insights into how power costs influence the price of power paid by consumers, we examine the methods used to determine power tariffs for different companies. Some tariff structures are entirely reflective of costs; in other cases, the changes in power costs are only partially transferred to consumers; and some tariffs are entirely subsidised, leading to no impact on power prices.

In each scenario, we analyse the effects of adding 1 MW of a specific technology on the price of power. We assume that a new plant operates on the lowest marginal cost of a given technology, if not otherwise specified. The cost specifics of the market-clearing plant are crucial in understanding how the price of power changes with this investment, because the market-clearing plant's output decreases with the additional investment, potentially resulting in cost reductions. Even though some countries do not have cost-reflective tariffs, our model assumes

[31] In Senegal in June 2022, outages because of fuel shortages occurred at several thermal plants. Given the idiosyncratic nature of the events, this is not accounted for in the model.

that reductions in the cost of power will be passed on to the end users. This may not be a realistic assumption in the short term but is much more likely in the longer term. Also, if these cost reductions are not passed on to the end users, they may positively affect the operations power system of the country in other ways.

Table 3 shows the changes in cost of power of investments in specific technologies. In general, renewables decrease the cost of power, whereas thermal energies provoke an increase because of their higher marginal cost. However, exceptions do exist, such as CCGT in Senegal and Côte d'Ivoire and solar PV and hydropower in Zambia. The first row shows the 1 MW addition as a percentage of the total generation capacity of the country, to get an understanding of the total impact of the investment on generation capacity. This explains, for example, why the impact on prices is less pronounced in South Africa, because its power sector is approximately 30 times larger than that of Senegal, making a 1 MW increase relatively smaller.

Table 3. Change in cost of power associated with addition of 1 MW of capacity

1 MW capacity	Côte d'Ivoire	Kenya	Mozambique	Senegal	South Africa	Zambia
1 MW as % of total generation capacity	0.046%	0.034%	0.035%	0.060%	0.002%	0.030%
Solar PV	-0.013%	-0.014%	-0.036%	-0.017%	-0.003%	0.006%
Solar PV & storage					0.001%	
CSP					-0.001%	
Wind		-0.008%	0.022%	-0.009%	-0.003%	-0.001%
Hydropower	-0.010%	-0.016%	-0.050%	-0.045%	-0.003%	0.015%
Geothermal		-0.021%	0.008%			-0.018%
CCGT	-0.012%		0.012%	-0.079%		0.011%
OCGT/HFO		0.009%		-0.061%	0.006%	0.003%
Coal					0.0%	0.003%

3.4.3. Δ GHG intensity (tCO_2e)

The assessment of changes in GHG intensity follows a similar methodology to that employed for the cost of power. Using data on GHG intensities per plant, we can calculate the total annual GHG emissions associated with the power generation of the specific power mix of each period.

Subsequently, we divide this annual figure by the total power generated to establish the GHG intensity of the system, expressed in metric tonnes of CO_2 equivalent (tCO_2e) per kWh generated. To bolster the robustness of our findings, we cross-reference our results with available data on the GHG intensity of the power system when available.

Again, we assume that a new plant has the same GHG intensity as the lowest value of a given technology, if not otherwise specified. When observing the change in GHG intensity related to investments in the power sector, the specifics of the market-clearing plant are again fundamental. With the additional capacity in the power sector, the market-clearing plant will produce less power, which may therefore also change the GHG intensity of the power system.

Table 4. Change in annual GHG emissions of adding 1 MW capacity, expressed in tCO_2e

1 MW capacity	Côte d'Ivoire	Kenya	Mozambique	Senegal	South Africa	Zambia
Total annual GHG emissions	3,085,814	1,474,023	952,123	2,460,560	183,650,901	1,252,687
Solar PV	-518	-1,337	-965	-882	-1,615	-1,976
Solar PV & storage					-3,277	
CSP					-1,918	
Wind		-957	-965	-1,317	-1,935	-1,240
Hydropower	-808	-1,317	-2,089	-2,094	-1,788	-3,915
Geothermal		-3,173	-3,120			-5,602
CCGT	+577		-90	-1,529		-99
OCGT/HFO		+369		+28	+160	+247
Coal					+1,768	+704

Table 4 displays the effects of power investments on GHG emissions for each of the technology types. Unsurprisingly, renewable energies bring about the highest reduction in GHG emissions, with geothermal, hydropower and solar PV & storage creating the highest reductions in GHG emissions. Investments in thermal energy tend to increase the level of GHG emissions, creating a trade-off with their high effect on reducing outages. One exception is Senegal, where investments in CCGT decrease CO_2 emissions as they replace HFO plants during peak hours, which produce 60% more GHG emissions per kWh.

The variation between countries in the impact of each technology on annual emissions is explained by two factors: (i) the frequency of outages; and (ii) the emissions of the last power plant in the merit order. As in reality, additional capacity in the model can either reduce 1 MW of lost load or, for technologies deployed earlier in the merit order, reduce the reliance on technologies later in the merit order. In countries with frequent outages, more of the additional renewable energy capacity goes towards reducing outages and thus cannot displace thermal plants at the end of the merit order. This explains, for example, the relatively low decrease in GHG emissions in Côte d'Ivoire, where the IPP investments contribute more to reducing the frequency and duration of outages than to reducing emissions.

To summarise the findings of the power model section, Table 5 ranks the technologies across three key dimensions: affordability (relating to the change in cost of power); reliability (related to outages); and GHG emissions. Stronger shifts, such as reduced cost of power, outages or GHG emissions, are indicated with ++, and a moderate shift is indicated with +. Similarly, a negative impact (such as an increase in cost of power or GHG emissions) is indicated by -- (stronger) or - (moderate). Clear trade-offs emerge for certain technologies, for instance between GHG emissions and reliability for solar PV and thermals. Other technologies – such as geothermal, hydropower and wind – score relatively well on all dimensions. We revisit this in Section 6, when we also factor in the capital costs of investments in these technologies.

Table 5. Technologies and their effects in terms of affordability, reliability and GHG emissions

1 MW capacity	Reduced cost of power	Reduced outages	Reduced GHG emissions
Solar PV	+	o/+	++
Solar PV & storage	-	++	++
CSP	-	+	+
Wind	+	+	+
Hydropower	+	+	+
Geothermal[32]	+	++	++
CCGT	-	++	-
OCGT/HFO	-	++	--
Coal	0	++	--

3.5. Extension(s) of the model

We now explain specific extensions to the model that were performed for some of the markets, including transmission investments and investments in different locations within the country.

3.5.1. Transmission in Kenya

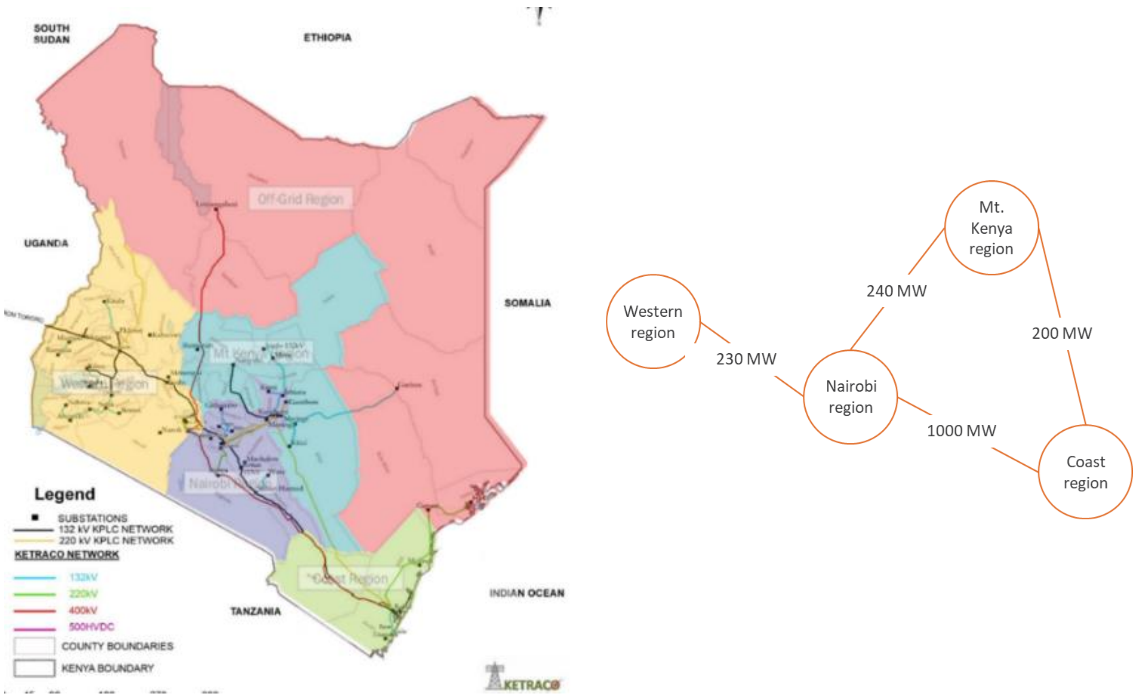
The power model matches available supply of power to demand, marking an outage when demand exceeds supply. However, there are other causes of outages. Transient outages can be caused by faults anywhere in the electricity grid and are outside this study's scope. The other main systemic cause of outages is a lack of transmission capacity – a country may have enough available power supply but may be unable to supply regions that are less well connected.

In Kenya, our existing supply and demand power model was unable to capture this significant cause of outages. Kenya generally has enough supply of power, especially in hydrologically wet years. Further research revealed that the outages were concentrated in the Nyanza region in western Kenya. A look at Kenya's transmission map (see Figure 10) reveals the issue: there is a bottleneck between the Nyanza region (yellow) and the rest of the country, with one underpowered transmission line linking it to Nairobi.

To accurately reflect the reality of the power situation on the ground in Kenya, it was imperative to add a transmission component to the power model. KPLC and KETRACO divide their administration of the grid into four connected zones and an off-grid zone. For modelling purposes, we simplified the transmission network to these four zones, because the key effect that needed to be captured was the prevalence of outages in the Western Region of Kenya.

[32] According to the U.S. Energy Information Administration (EIA), geothermal power plants emit 97% less acid rain-causing sulphur compounds and about 99% less CO_2 than fossil fuel power plants of similar size. Because these emissions are different for each well and because they are two orders of magnitude smaller than fossil plants, we have assumed zero emissions for geothermal plants in this report.

Figure 10. Kenya's regions used for grid management, and the simplified transmission structure in the model



To extend the supply side of the power model, the generating plants were divided into zones. The calculation of the matching exercise was updated in line with Kenya's technology-based merit order. The demand was distributed among the four regions using 2022 regional demand data from KPLC. Thus, all the feed-in renewable power produced in each region was calculated first and was reallocated or transmitted across zones based on need. This was then repeated with geothermal plants, hydropower plants and, lastly, thermal plants. At each step, the remaining transmission capacity was updated, to ensure that the merit order was being followed without exceeding the transmission capacity.

Electric power does not function as described above. Electricity does not have to be pushed across lines; rather, the utility coordinates power plants and transmission substations to ensure that the voltage remains steady and that available power exceeds the demand by the reserve margin amount. However, for planning purposes, our transmission model aims to reflect how the decisions to switch on dispatchable plants at Kenya's National Control Centre are made. The calculations of outages are also segmented regionally, allowing the model to differentiate between nationwide outages and outages in the Western Region.

It is now possible to model the effect of increasing the transmission capacity rather than the generation capacity. To keep results comparable with the IPP generation interventions, a 1 MW addition to the transmission line between the Nairobi and Western regions was modelled. Adding this transmission capacity led to a 1,075 MWh reduction in outages, increased the cost of power by 0.015%, and led to a GHG emissions reduction of 498 tCO_2e/y.

To provide context, we can compare this against the most effective IPP generation intervention: adding 1 MW of geothermal energy to western Kenya. This generation capacity would lead to a 1,666 MWh reduction in outages, decrease the cost of power by 0.030%, and lead to a GHG emission reduction of 3,633 tCO_2e/y. However, this relies either on development of the very limited geothermal potential in the region (i.e. Homa hills) or on expanding the existing geothermal fields in the Olkaria region, which are subject to the same transmission bottleneck.

Per MW, geothermal also costs approximately six times as much as an investment in a transmission line. Adding 1 MW of wind in the Western Region, a more realistic option, would reduce outages by 571 MWh, decrease cost of power by 0.007%, and reduce emissions by 1,060 tCO_2e/y, while still costing over three times as much per MW. Investments in transmission can reduce emissions and outages more cost-efficiently than investments in generation.

3.5.2. Solar with battery storage in South Africa

When adding a solar PV plant with attached battery storage (Battery Energy Storage System (BESS)) to the grid, the key consideration is to maximise the utility of the battery, because it is often the most expensive component. Given that most of the utilities in this study provide a fixed feed-in tariff to encourage development of renewable IPPs, the financial objective for the IPP is to maximise power delivered throughout the day. The impact objectives are to maximise the power delivered during peak hours and to maximise the utility of the solar power produced. Hence, to maximise their financial returns, IPPs would have to use the battery to store excess solar power during the day that cannot be transmitted, and deliver it at night, bringing the financial and impact objectives into alignment.

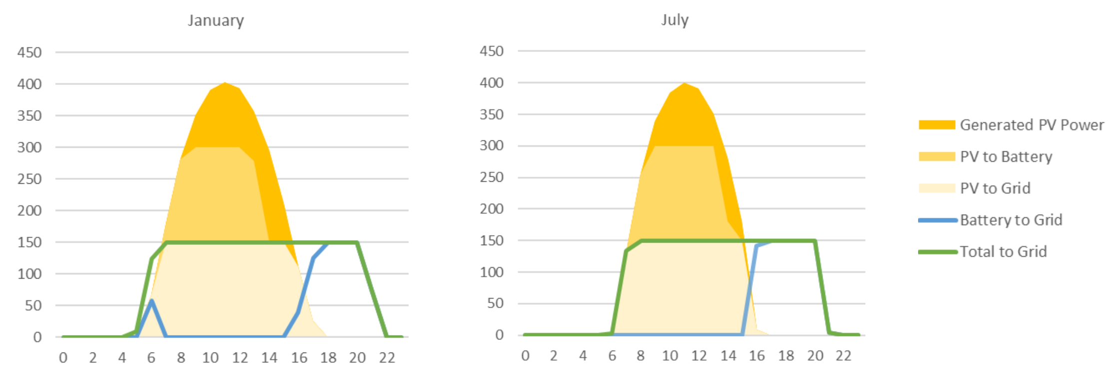
To model a solar PV with battery storage plant, we need information on the solar plant's capacity, the battery's power capacity and energy storage capacity, and the capacity of the grid connection. To integrate such a plant within an hourly model, we need to develop the charging pattern for the battery. This requires an estimate of the planned lifetime of the battery. Our model has the following key considerations and constraints:

- the objective was to maximise the power delivered between 5:00am and 9:00pm;
- the battery is subject to 0.60 cycles a day, ranging from 20% to 80% of capacity; and
- a round-trip efficiency of 86%.

Using data on solar power availability throughout the seasons, a battery charging pattern was developed for the different months of the year. See Figure 11 for a comparison of the developed charging pattern and power delivered to the grid.

The total power delivered to the grid is then used as the supply factor in the power model. Solar PV with storage plants were modelled for the Kenhardt plant in South Africa (see 'Projected impact of Kenhardt' in Annex 5). The analysis of this type of BESS plant has only been performed in South Africa.

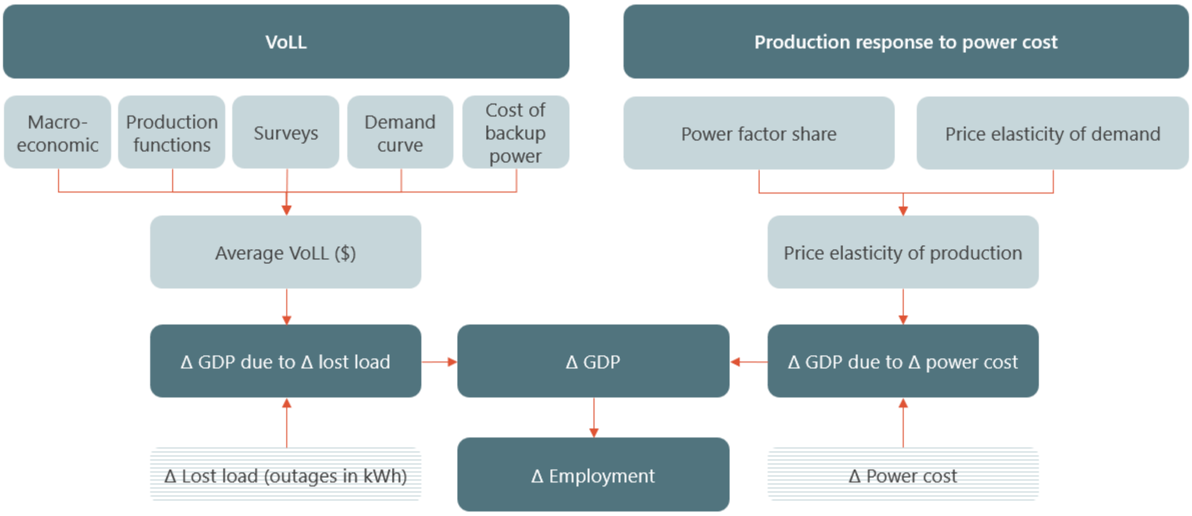
Figure 11. Generated solar power, battery charging pattern and supply of power to the grid in January and July



4. Modelling of the private sector

The private sector responds to changes in cost and reliability of power. As shown schematically in Figure 12, we develop methods to translate the outputs from the power model in this section – changes in outages and power cost – to a change in value added, which is equivalent to GDP contribution. This requires quantifying the economic value of the power that was lost because of outages (VoLL) and determining how the private sector will respond to a change in power cost. We note that in this section we focus on the short-run response of the private sector. The long-run response, which encompasses new firm entry and capital investments that increase capacity and productivity and hence results in increased demand for power over time, can be substantially larger.33 In the absence of a coherent framework and data to quantify the long-run response, we focus on the short-run response as a conservative estimate of the total response.

Figure 12. Overview of the private sector response



[33] Fried, S. and Lagakos, D. (2023) 'Electricity and firm productivity: A General-Equilibrium Approach'. *American Economic Journal: Macroeconomics* 15(4): 67–103.

4.1. VoLL

Power interruptions or outages are complex phenomena that are influenced by many stochastic factors. As mentioned in Section 3.4, technical reliability of the power system is often measured using a set of indicators that capture frequency and duration of power outages. However, these indicators do not capture the economic costs incurred by individual users or the aggregate macroeconomic costs. These costs range from backup power generation, opportunity costs of idle resources, damage to equipment and lost inventory to delayed deliveries along the value chain. Many of these costs are short-run in nature and may or may not be partially mitigated, but there are also longer-run economic costs, such as foregone investments in productivity enhancements and business entry, which we do not consider here.

To estimate the effect on the real economy of the intervention in the power system, we use the concept of VoLL, which represents what society ought to be willing to pay to avoid a power outage. VoLL can be used to help policymakers, utility companies and investors to quantify the benefits of improved power reliability. VoLL is defined as:

$$VoLL = \frac{Economic\ value\ lost\ (\$)}{Lost\ load\ due\ to\ outages\ (kWh)}$$

VoLL is inherently heterogeneous and varies by, among other factors: (i) country, customer segment and economic sector; (ii) season and time of day; and (iii) duration and frequency of outages and advance notice. In most cases, VoLL is not a directly observable quantity. Below we approximate VoLL using five different estimation methods.[34] Each method suffers from disadvantages, and values reported in literature span a wide range. By taking the average of all five methods, we find defensible economy-wide[35] estimates of VoLL in each of the different countries. Table 6 summarises the results.

There have been limited studies of the VoLL in developing countries. In an overview study, Van der Welle and Van der Zwaan (2007)[36] estimate that the VoLL in developing countries is likely to be between $2/kWh and $5/kWh in 2030. In a study in Cameroon (2013),[37] VoLL was estimated to be between €3.62/kWh and €5.42/kWh for a one-hour interruption and from €1.96/kWh to €2.46/kWh for a four-hour outage. Both studies provide supporting evidence that the estimates of VoLL found in this study are realistic.

Table 6. Estimation of VoLL for the six countries in this study ($/kWh)[38]

Estimation method	Côte d'Ivoire	Kenya	Mozambique	Senegal	South Africa	Zambia
Macroeconomic	4.31	4.88	3.74	3.64	5.46	2.32

[34] For a more extensive overview on VoLL and ways to measure it, see Schröder, T. and Kuckshinrichs, W. (2015) 'Value of Lost Load: An efficient economic indicator for power supply security? A literature review'. *Frontiers in Energy Research* 3.

[35] One economy-wide VoLL estimate purposely averages out underlying heterogeneity, as in substantially all societal cost-benefit analyses. Summarising the state of VoLL research, Gorman (2022) states: "There remains a ripe [but largely unexplored] opportunity to study how the heterogeneity between different valuation approaches (such as proxy, surveys, and revealed preference) could be used to triangulate a VoLL and characterise a wider distribution of Cost Benefit Analysis than performed in previous studies."

[36] Van der Welle, A. and Van der Zwaan, B. (2007) 'An Overview of Selected Studies on the Value of Lost Load'. *Energy Research Centre of the Netherlands*.

[37] Diboma, B. and Tamo Tatietse, T. (2013) 'Power interruption costs to industries in Cameroon.' *Energy Policy* 62: 582–92.

[38] The various estimation techniques have underlying data from different years. We have used the most recent years for which data was available for each of the estimation techniques.

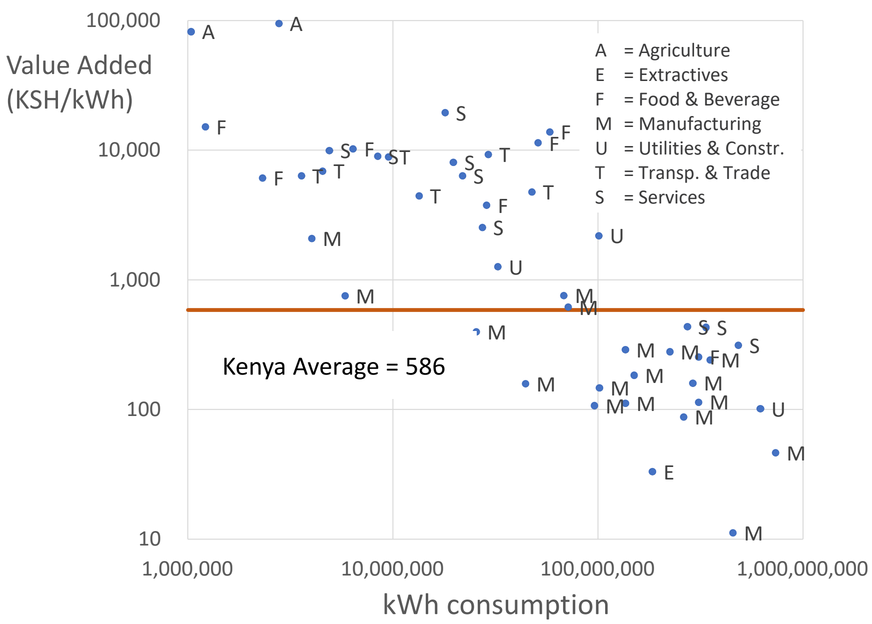
Production function	2.62[39]	2.98	3.04	2.62[39]	2.31	2.15
Survey-based	3.81[39]	4.93	4.89	3.81[39]	1.57	3.87
Demand curve	2.29	2.88	3.20	2.96	2.31	2.62
Backup power cost	3.50	3.50	3.50	3.50	3.50	3.50
Average	**3.31**	**3.83**	**3.67**	**3.31**	**3.03**	**2.89**

4.1.1. Macroeconomic data

VoLL can be estimated for an entire economy, as well as for individual economic sectors, using social accounting matrices[40] by dividing the value added of an economy or sector by the total power consumption. Figure 13 shows the results for Kenya.

Sectors that do not use much electricity tend to produce a lot of value per kWh and show up in the top-left corner, whereas sectors that use a lot of electricity tend to produce less value added per kWh and are in the bottom corner. This points to a weakness with regard to determining VoLL per sector in this way: sectors that use little energy (such as construction, agriculture or some business services) are most likely able to mitigate the effect of outages, simply because electricity is not (time-)critical to production. Their VoLL would therefore be small, rather than very large as in the graph. Nevertheless, at the scale of an entire economy, the measure is often used.[41] For Kenya, the VoLL estimated in this way is KSh 586 ($4.88)/kWh. This overall value is obviously much more influenced by the power-intensive sectors located on the right in Figure 13. The higher value ($5.46) for South Africa points to it being a more power-intensive economy.

Figure 13. Estimation of VoLL using macroeconomic data



[39] Owing to a restricted sample size and outdated data (the most recent WBES survey was conducted in 2014 in Senegal and 2016 in Côte d'Ivoire), we rely on averages from the remaining four countries when applying these methods to Senegal and Côte d'Ivoire.

[40] We use social accounting matrices from the BII-initiated Joint Impact Model, derived from the Global Trade Analysis Project.

[41] Cambridge Economic Policy Associates (2018) 'Study on the estimation of the value of lost load of electricity supply in Europe'.

4.1.2. Production function

Each firm responds in a different way to an electricity outage. Some may have to cease production entirely because electricity cannot be substituted. Others can continue to (partially) operate, meaning that electricity can be substituted by other inputs. These two approaches can be expressed in two so-called production functions:

$$Y = \min\left\{A \cdot K^{\alpha} \cdot L^{\beta} \cdot M^{\gamma}, \frac{1}{\lambda} E\right\} \text{ (Leontief)}$$

$$Y = A \cdot K^{\alpha} \cdot L^{\beta} \cdot M^{\gamma} \cdot E^{\delta} \text{ (Cobb-Douglas)}$$

where Y is firm output (revenues), A is the total factor productivity, K is capital, L is labour, M is materials and E is electric power. The Greek letters indicate factor shares, except for λ, which is the electricity intensity of a company. Unlike the Leontief production function, the Cobb-Douglas one allows for substitution between inputs. We note that more advanced production functions can be deployed. For example, Colmer et al. (2023)[42] used a production function in which the real cost of electricity depends on the productivity of the power sector. But we deem more sophisticated production functions than the two proposed above unnecessary considering the highly aggregate nature of VoLL at the country scale and considering the data sources.

The two production functions can be translated into expressions of VoLL:

$$VoLL_{Leontief} = \frac{VA}{Y} \cdot \frac{Y}{E}$$

$$VoLL_{Cobb-Douglas} = \delta \cdot \frac{VA}{Y} \cdot \frac{Y}{E}$$

where $\frac{VA}{Y}$ is the economic value added/output ratio.

The electricity factor share δ is typically in the range 0.05–0.15 (see Table 7). By taking the average of these two limiting forms, we obtain:

$$VoLL = \frac{1+\delta}{2} \cdot \frac{VA}{Y} \cdot \frac{Y}{E}$$

The ratio $\frac{VA}{Y}$ and the electricity factor share are estimated[43] using data from the WBES in the respective countries. Although, for the most part, the Enterprise Survey covers manufacturing firms, it is these firms especially that determine the VoLL for a country (see Figure 14).

It appears that the values obtained in this way are a little over half of those obtained in the macroeconomic estimations (see Table 6). The explanation for this is that the macroeconomic estimation is essentially the same as the Leontief estimate and the electricity factor share is typically rather small.[44] However, the two estimations use different data sources (macroeconomic data vs microeconomic survey data), and the fact that the same (the Leontief) estimation delivers very similar values using these different data sources is reassuring.

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[42] Colmer, J., Lagakos, D. and Shu, M. (2024) 'Is the electricity sector a weak link in development?' NBER Working Paper 32041. The authors hypothesise that, although the productivity of electricity sector in low-income countries is not far behind that of advanced economies, idle or damaged capital equipment in the wider economy is a channel through which electricity can be a weak link in development.

[43] The ratio *VA/Y* can be derived straightforwardly from the data, whereas estimation of δ requires log-linear regression. Because firms can be used only if they have completed all relevant questions, the sample size reduced substantially. For example in Kenya, out of the 1,001 firms in the survey, and after removing outliers, data from 187 companies could be used.

[44] This means that the ratio $\frac{1+\delta}{2} \approx 0.5$ and thus the estimation for $VoLL_{Cobb-Douglas}$ is ≈ 0.5 times the $VoLL_{Leontief}$.

4.1.3. Survey-based method

The WBES also ask firms to provide an estimation of the duration and frequency of power outages and the sales they have lost due to them. Together with the survey data on monetary electricity spent and the average commercial price of power in the year of the survey, estimates of VoLL can be derived. VoLL estimates at a sectoral level range from \$4.32/kWh for food processing to \$6.26/kWh for chemical, pharmaceutical and plastic. The average for all manufacturing sectors is \$4.93/kWh. This small range masks the considerable heterogeneity between individual firms, which range from virtually \$0 to \$42/kWh. Apeti & Ly (2023)[45] also deploy data from the WBES to calculate the impact of outages on total factor productivity in developing countries. On average, they find that firms exposed to outages have an average productivity that is 9% lower than that of non-exposed firms. These results, however, do not estimate the VoLL per kWh.

4.1.4. Demand curve estimation

For an individual firm, VoLL is the difference between its willingness to pay for electricity and the actual price it pays. In other words, VoLL is equal to the lost consumer surplus during an outage. If the demand curve for electricity were known, one could estimate VoLL by taking the integral between the demand curve and the actual price paid for power.[46] However, the demand curve for power is hardly ever known and must be approximated from the price elasticity of electricity demand, which is available for a substantial number of countries in the literature.

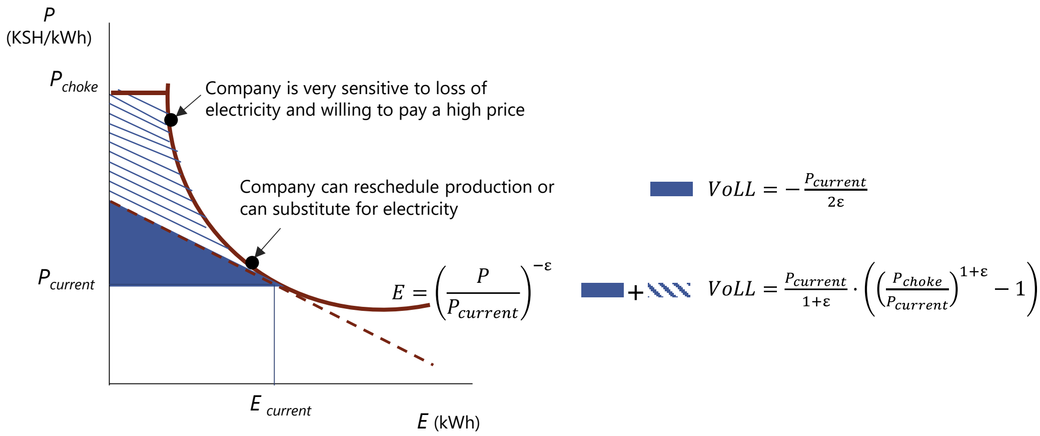
The price elasticity is not sufficient and still requires the specification of the functional shape of the demand curve, which describes electricity consumption E (horizontal) as a function of electricity price P (vertical). Figure 14 shows two often-used forms: a linear demand curve (straight line) and a constant elasticity demand curve. In the latter, the demand for electricity vanishes only at an infinitely high electricity price. This requires the imposition of a 'choke' price, above which all electricity consumption from the grid would vanish.[47] Figure 14 also shows the expression for VoLL (the coloured areas representing consumer surplus) for the two demand curves as a function of the current electricity price and the price elasticity of electricity consumption, ε (see Table 7 for the used price elasticities of the individual countries).

[45] Apeti, A.E. and Ly, A. (2023) Power Constraints and Firm-Level Total Factor Productivity in Developing Countries. World Bank Policy Research Working Paper 10510.

[46] Gorman, W. (2022) 'The quest to quantify the value of lost load: a critical review of the economics of power outages.' *The Electricity Journal* 35(8).

[47] Here we use a choke price of 6–10 times the cost of backup power – about \$2–\$5/kWh. Although the variable cost of backup power is about \$0.40/kWh, the capital costs are considerable and are spread over typically low consumption, causing the effective price per kWh to be much higher. The imposition of a choke price introduces circularity in the reasoning, but the more elastic demand is, the less it influences the result. When using backup power for some 70–140 hours per year (which approximately coincides with the previously presented outage data), a per kWh price of \$2–\$5/kWh is realistic (see next section on backup power).

Figure 14. VoLL as lost consumer surplus using two functional shapes of the demand curve



Because we know that the linear demand curve substantially underestimates VoLL, in Table 6 we use the average of constant elasticity demand curve estimation with two different choke prices (for all countries) – $2/kWh and $5/kWh – and different price elasticities.[48]

4.1.5. Cost of backup power (revealed preference)

It can be inferred from the WBES that many firms use some kind of backup power generation. In most of the six countries covered in this report, about two out of every three firms have some sort of backup or self-generation (e.g. 64% in South Africa and 68% in Kenya). In fact, some of the medium and large firms self-generate one-quarter to one-half of their total electricity consumption.[49] For that reason, we estimate VoLL as the cost per kWh of a backup generator that is being used for 50–100 hours per year. The cost of self-generation for this range of hourly usage is estimated at $2–$5/kWh.[50] As a universal estimation of VoLL for all countries, we take the average value of $3.50/kWh.

[48] For Kenya price elasticity, Njeru (2020) found -0.03 and Onuonga et al. (2011) found -0.08. For South Africa, Masike and Vermeulen (2022) found -0.29, Blignaut et al. (2011) found -0.32, and Inglesi-Lotz (2011) found -0.56. For Zambia, Chama (2012) found -0.06 and Mashekwa et al. (2019) found -0.18. For Côte d'Ivoire, Mozambique and Senegal, Atalla et al. (2016) found -0.16, -0.02 and -0.05 respectively.

[49] Full self-generation typically requires very large generation capacity to deal with peak requirements and is most often not feasible.

[50] Gorman, W. (2022) 'The quest to quantify the value of lost load: a critical review of the economics of power outages'. *The Electricity Journal* 35(8).

4.2. Private sector response to a change in power price

A second channel through which the private sector responds to the intervention in the power system is through the change in the price of electricity. This is contingent on the price elasticity of power consumption, defined as:

$$\frac{dE}{dP} = -\varepsilon \cdot \frac{E}{P} \Longrightarrow \frac{\Delta E}{E} = -\varepsilon \cdot \frac{\Delta P}{P}$$

The second part of the equation states that the relative increase of electricity consumption is inversely proportional to the relative change in electricity price multiplied by the price elasticity. As mentioned in Section 4.1.4, for several countries in this report price elasticities can be found.

Next, we estimate how the output and value added of firms change in response to the increased consumption of power. Based on the Cobb-Douglas production function (see Section 4.1.2), the relative change of value added in response to a relative change of electricity consumption, and hence electricity price, can be written as:

$$\frac{\Delta VA}{VA} = \frac{\Delta Y}{Y} = \delta \cdot \frac{\Delta E}{E} = -\varepsilon \cdot \delta \cdot \frac{\Delta P}{P}$$

The second part of the equation states that a relative change in value added (or GDP) is inversely proportional to a change in price, multiplied by the factor share and the price elasticity (meaning a lower price increases value added). Table 7 summarises the price elasticity and factor share of electricity for the six countries. When the price changes from Section 3.4.2 are multiplied by the product $\varepsilon \cdot \delta$, the value added (and thus the GDP) response of the economy is obtained. As an illustration, an electricity price decrease of 1% in South Africa leads to a GDP increase of 0.04%.

Table 7. Price elasticity and electricity factor share

Estimation method	Côte d'Ivoire	Kenya	Mozambique	Senegal	South Africa	Zambia
Price elasticity ε	-0.16	-0.03	-0.02	-0.05	-0.29	-0.12
E-factor share δ	0.16[51]	0.13	0.25	0.16	0.14	0.10
$\varepsilon \cdot \delta$	-0.0256	-0.0039	is-0.005	-0.008	-0.0406	-0.012
Sample size	40	187	216	90	257	146

4.3. Employment impacts

Once the GDP response to a power investment is known, this can be translated into an estimated employment impact using the country's labour statistics, assuming that labour productivity is unchanged:

[51] Owing to a limited sample size for Côte d'Ivoire and Senegal, a sample including all six countries is used to estimate the factor share of electricity.

$$\frac{\Delta L}{L} = \frac{\Delta GDP}{GDP} \Longrightarrow \Delta L = \frac{\Delta GDP}{GDP/L}$$

The equation states that the change in employment is equal to the change in GDP divided by the GDP per worker, or the labour productivity. Because of the very different labour productivity of the formal and the informal economy, these must be distinguished. We will focus on the formal economy results because it consumes the bulk of the electricity. This is done by considering the formal fraction, *f*, of GDP and the formal labour force, L_f. We assume that the GDP increase arises entirely in the formal sector. This results in the following equation:

$$\Delta L_f = \frac{\Delta GDP}{f \cdot GDP \,/\, L_f}$$

Although this may be a slight overestimation[52] of the formal employment effect, we do not consider the spillover effects into the informal sector, such as through the supply chain of formal companies. The employment results reported in this report are therefore defensible. The larger the formal sector employment productivity, which is the numerator, the smaller the employment effect for the same change of GDP. Table 8 summarises the various economic variables needed to determine the formal sector labour productivity.

Table 8. Economic and employment characteristics of the six countries

Estimation method	Côte d'Ivoire	Kenya	Mozambique	Senegal	South Africa	Zambia
Current GDP ($ billion)[53]	71.81	110.35	18.41	27.68	419.02	22.10
Formal fraction (*f*)[54]	57.7%	67.4%	69.0%	62.2%	71.2%	61.0%
Total people employed (*L* in million)[55]	9.99	22.70	14.14	4.97	16.82	6.53
Formal employment (L_f in million)	1.12	3.84	1.12	1.01	10.38	1.34
$f \cdot GDP/L_f$ ($/FTE)[56]	36,995	19,369	11,342	17,068	28,742	10,060

[52] It is unlikely that a more reliable electricity supply results in a large output in the informal sector, because informal companies are much less electricity-intensive. In fact, they will normally not be able to contract an electricity connection.

[53] World Bank national accounts (2022).

[54] Sources are indicated for the individual countries in the respective annexes.

[55] International Labour Organization (1996–2024) 'Indicators and data tools'. https://ilostat.ilo.org/data/

[56] FTE: Full-Time Equivalent.

5. Results

5.1. GDP results

We combine the results from the power model with the results from the private sector responses to calculate the effects on GDP and employment. These are captured by the following formulas:

$$\Delta\ GDP_{Lost\ load} = \Delta\ Lost\ load \cdot VoLL$$

$$\Delta\ GDP_{Cost\ of\ power} = \Delta\ Power\ cost(\%) \cdot \varepsilon \cdot \delta \cdot GDP$$

The GDP effects of power sector interventions of specific technologies are summarised in Table 9. Across the board, the outages effect dominates the cost of power effect in terms of impact on GDP. For a split of the relative magnitude of the outages and cost of power channels, we refer to the results tables in the country-specific annexes. Except for Senegal, which experiences no generation-related outages, the biggest GDP effects come from reducing outages.

Table 9. Annual change in GDP associated with addition of 1 MW capacity (in $ million)

1 MW capacity	Côte d'Ivoire	Kenya[57]	Mozambique	Senegal	South Africa	Zambia
Solar PV	0.64	0.06	0.03	0.02	2.11	0.01
Solar PV & storage					5.65	
CSP					3.73	
Wind		0.58	0.04	0.01	2.86	0.12
Hydropower	0.64	0.77	0.12	0.06	2.82	0.26
Geothermal		1.75	0.17			0.41
CCGT	4.41		0.19	0.11		0.52
OCGT/HFO		1.82		0.09	4.52	0.53
Coal					4.73	0.54
Transmission		7.23				

[57] The results shown here for Kenya are for a hydrologically normal year. In dry years, the impacts are markedly larger (see Figure 23 for reserve margin under dry conditions).

In Côte d'Ivoire, CCGT has an outsized impact on GDP compared to the other technologies, because of its stable power supply throughout the day and thus its substantial impact on reducing outages. Because of lower availability factors, renewables generate smaller impacts on GDP. It is important to note that the Côte d'Ivoire results reflect the situation in 2021, when the breakdown of the Azito power plant near the capital, Abidjan, caused substantial load shedding. In normal years the country has a power surplus, which is exported to its neighbours.

In Kenya, addressing the transmission bottleneck to the Western Region would have a substantial impact – almost four times higher than the next best intervention (OCGT/HFO). Solar PV, on the other hand, is only available during the day and therefore does not lead to any impact on Kenyan GDP through outage reduction. We also expect the large impact of transmission elsewhere, to alleviate intra-country bottlenecks and/or to achieve regional power pools that can be operated more efficiently (see Section 6.5).

In Mozambique, impacts are considerably smaller because of the limited incidence of outages. Table 9 does not consider the possibility that Mozambique could export its electricity surplus to South Africa, such as that of the new CCGT Temane power plant. In fact, the results would then be comparable to those for OCGT and coal in South Africa, but the impacts would, of course, accrue there as well (we will revisit this in Section 6).

In Senegal, GDP impacts are only driven by a change in the price of power, which explains a marginal impact compared to the other countries.

South Africa experiences the largest effects on GDP from all technologies because of frequent load shedding and a power-intensive economy; capacity additions of any type help to reduce this, because outages take place across the day.

In Zambia, thermal technologies also outperform renewables because of their higher availability. For most technologies there is a negative price effect, owing to the artificially low price of government-subsidised hydropower in the baseline scenario (we come back to this later).

5.2. Employment results

Table 10. Change in formal jobs associated with addition of 1 MW capacity

1 MW capacity	Côte d'Ivoire	Kenya	Mozambique	Senegal	South Africa	Zambia
Solar PV	37	3	3	1	73	1
Solar PV & storage					196	
CSP					130	
Wind		24	4	1	100	12
Hydropower	37	32	11	4	98	25
Geothermal		73	15			41
CCGT	259		17	7		51
OCGT/HFO		76		5	157	53
Coal					165	53
Transmission		302				

Table 10 summarises the change in formal jobs associated with the different IPP investments. There is a high correlation between GDP and employment effects, because we assume constant labour productivity to calculate the employment effects. Relative differences between countries stem from the variety in employment intensities of the economies. Because of the strong correlation, we will focus our economic analysis on GDP effects in the remainder of this section (for a more detailed breakdown of the employment effects, see the country-specific annexes).

The method we used in this study helps us to see how different changes can affect the whole power sector. However, our method does have some limitations. For example, the model focuses mainly on the short-term economic effects of investments and does not consider long-term changes such as companies improving productivity or new companies starting up. Furthermore, estimating VoLL is challenging because of its heterogeneity among various consumer groups and sectors. Consequently our calculations, derived from multiple methodologies, can only offer a reasonably accurate estimate.

However, the results offer a clear direction regarding interventions that yield significant outcomes concerning their climate and developmental impact. Additionally, they shed light on the trade-offs that exist between considerations for climate and development. In Section 6 our focus will shift to examining the implications of this analysis from an investor's standpoint.

6. Synthesis of economic and climate impact

We now consider the results by looking at strategies to maximise impact by investing in Africa's electricity sector. How can one best distribute investments across different geographies and technologies, considering the nexus of development impact and climate neutrality at which these investments operate? In Section 6.1 we provide a quantitative definition of the climate–development nexus. By considering the capital cost of the various technologies and by introducing a carbon price, the GHG and GDP results (see Sections 3.4.3 and 5.1 respectively) can be evaluated in a single framework. The most important factors that need to be considered when making power investment decisions are discussed in the subsequent sections.

6.1. Climate–development nexus

The first step in defining the climate–development nexus is the translation of capacity additions into investment amounts. The GHG and GDP results per MW can then be translated into results per $1 million invested. Table 11 shows the total investment costs for 1 MW of each technology type in this research. We base our overnight costs on EIA (2022) and include the capital costs of investing in power in Africa by using an annual weighted average cost of capital of 10%, as well as the time span from the beginning of construction to the end of the plant's operation.[58]

Table 11. Total investment cost estimates of different technologies

Technology type	Base overnight cost (m$/MW)[59]	Weighted average cost of capital[60]	Lead time (years)[59]	Total investment cost (m$/MW)[61]
Solar PV	1.32	10%	2	1.60

[58] We have chosen not to differentiate the weighted average cost of capital (which includes the cost of equity and debt) between countries. Although this can easily be done, we reckon that the uncertainty around actual overnight costs and lead time outweigh the benefit of doing so here.

[59] Capital costs and lead time are sourced from US Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

[60] Based on cost of capital estimates by EIA (2022) of power investments in selected countries in Africa. We deploy 10% as an approximate average across different technologies and countries.

[61] Total investment costs = Base overnight costs × (1 + WACC)^Lead time.

Solar PV & storage	1.75	10%	2	2.12[62]
CSP	7.90	10%	3	10.51
Wind	1.72	10%	3	2.29
Hydropower	3.08	10%	4	4.51
Geothermal	3.08	10%	4	4.50
CCGT	1.29	10%	2	1.56
OCGT/HFO	0.79	10%	2	0.96
Coal	4.07	10%	4	5.96

For the transmission line modelled in Kenya, a capital cost of $0.52 million per MW was calculated using the length of the KETRACO transmission line built from Olkaria (Nairobi Region) to Kisumu (Western Region) and the average unit investment cost for a 400 kilovolt (kV) overhead line.[63] These costs were validated against the costs of the upcoming Africa50 public-private line between Kisumu and Masuga.

Figure *15* considers the climate–development nexus, examining the GDP and GHG effects per unit of capital invested. The graph therefore combines economic development and climate impacts and the capital efficiency of achieving those. The higher a country/technology combination, the more positive is its climate impact, and the farther to the right, the greater is the economic impact. Because the horizontal axis is logarithmic, the size of the GDP impact increases very rapidly towards the right.

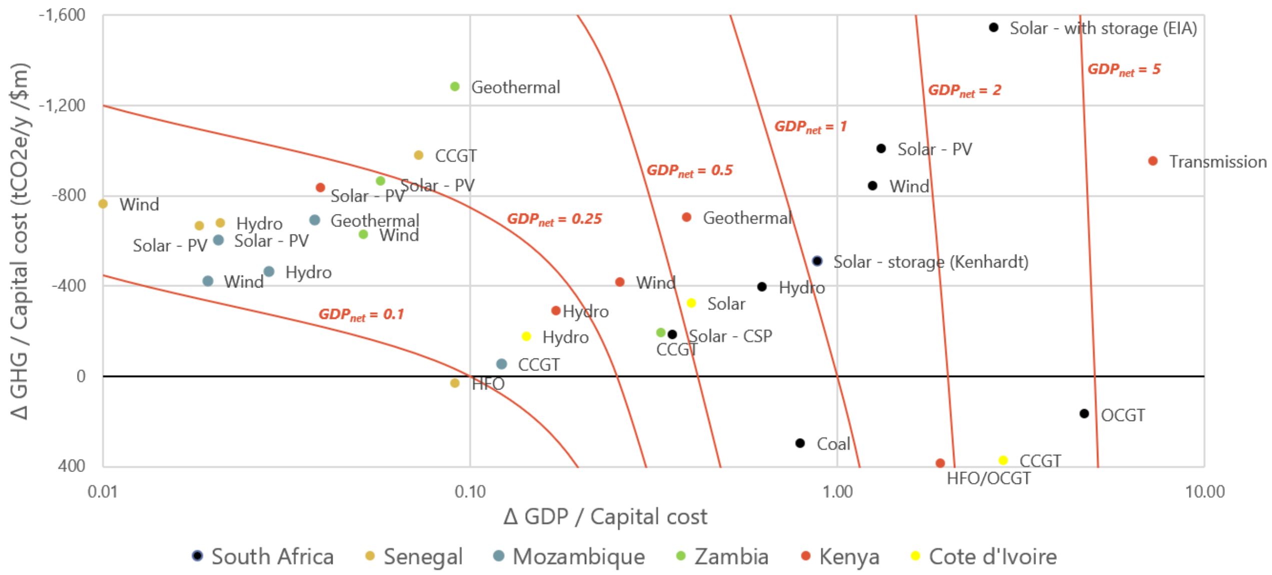
Most technologies present a distinct trade-off between developmental and climate impacts. Towards the bottom-right side of the graph, we see thermal technologies in countries with substantial outages (OCGT in South Africa, CCGT in Côte d'Ivoire and OCGT/HFO in Kenya), because they provide a cheap and easily dispatchable electricity source that alleviates outages. They have a large impact on GDP, but they increase GHG emissions. Towards the top-left side of the graph we find many renewables in countries with limited outages, such as solar PV and geothermal in Zambia and CCGT in Senegal. These technologies have a limited GDP impact but significantly curb GHG emissions. The great GHG-reducing impact of CCGT in Senegal seems counterintuitive because it is a non-renewable technology. However, Senegal relies on HFO, which emits 60% more tCO_2e/kWh than CCGT; and because CCGT replaces HFO during peak hours when solar PV is unavailable, it proves to be more effective than solar (which has a similar capital cost) in reducing GHG emissions in Senegal. In addition, although hydropower is more effective in reducing GHG emissions per MW installed, it is three times as expensive in terms of capital cost; and wind is similarly effective in reducing GHG emissions but is also 1.5 times more expensive than CCGT. Certain technologies also showcase a significant positive effect in both curbing GHG emissions and boosting GDP, positioning them more to the top-right part of the graph. For instance, transmission and geothermal in Kenya and solar with storage (with EIA investment cost), solar PV and wind in South Africa exhibit these characteristics.

[62] This is significantly lower than investment costs of the Kenhardt Power Plant in South Africa ($6.30mn/MW; see Annex 5 for more details). Costs are projected to drop further because of research & development (R&D) and scale effects in the production of batteries.

[63] European Union Agency for the Cooperation of Energy Regulators (2023) Unit Investment Costs Indicators for Energy Infrastructure Categories. https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_UIC_indicators_table.pdf

In general, the higher the capital cost, the greater the pull towards the origin. For example, CSP has larger impacts per MW than solar PV but has a capital cost that is ~6.5 times higher, which reduces both the GDP and GHG impact per dollar. We note the great potential of solar with battery storage when using cost estimates as provided by the EIA. However, at the capital cost of the Kenhardt plant,[64] solar PV and wind are currently the more efficient options, but this may change when battery storage continues to become cheaper. In contrast to the small impact of solar PV in Kenya, the large impact of solar PV in South Africa is explained by the fact that there are power shortages during the entire day. Any capacity addition will help alleviate these, and solar PV with very low capital costs has a large GDP effect per investment dollar.

Figure 15. *The climate-development nexus of different IPP investments*[57] *and isoquants assuming a carbon price of $200 per* tCO_2e



For 'pure-play' climate or economic development investors, the graph allows for easy ranking of investment options. For example, a climate investor would rank options by reading the graph from top to bottom, that is, irrespective of GDP impact. Solar with storage in South Africa (at the EIA investment cost) would come out on top because it has the highest GHG (avoidance) impact per unit of invested capital. Conversely, an economic development investor would rank options by moving from right to left to pick options with the greatest GDP impact per dollar, irrespective of climate effects. Transmission in Kenya, followed by OCGT in South Africa, then emerge as the most appealing investments, because they have the highest GDP impact per invested capital unit.

For other investors, balancing climate and developmental objectives can be challenging. By introducing a carbon price, P_{GHG}, the GHG emissions can be monetized and subsequently collapsed into a climate-corrected or 'net GDP' measure:

$$\frac{\Delta GDP_{net}}{C} = \frac{\Delta GDP - \Delta GHG \ \cdot P_{GHG}}{C}$$

where C denotes the investment cost in $ million.

For investments that avoid carbon emissions (by pushing out higher GHG-emitting plants), the net GDP effect will increase relative to the uncorrected GDP measure, and the opposite is true

[64] The Kenhardt plant is dimensioned to deliver constant power for 16.5 hours per day instead of standard solar PV plus four hours, and capital costs cannot be directly compared with EIA estimates.

for technologies that add to the grid-wide GHG emissions. In Figure 15, the orange lines indicate the isoquants along which ΔGDP_{net} is constant. The isoquants are downward sloping because ΔGDP_{net} increases with higher GHG avoidance, that is, higher up in the graph. The reason that the isoquants are not straight lines is because of the logarithmic scale used on the horizontal axis. Where each isoquant intersects the horizontal axis, $\Delta GHG = 0$ and ΔGDP_{net}= ΔGDP. For a carbon price $P_{GHG} = 0$ the isoquants will be vertical, that is, ΔGDP_{net}= ΔGDP. The higher the carbon price, the more horizontal the isoquants will be, meaning that ΔGHG has a larger impact on ΔGDP_{net}.

Based on this framework, an investor can set a reference carbon price to assess the trade-offs between climate and development. Based on that carbon price, a ranking can be made in terms of the technology-country combinations that yield the highest impact. Even for investors such as BII that only invest in renewable power technologies, a carbon price can be relevant because renewable technologies differ in their ability to avoid carbon emissions from fossil sources, as shown by the results.

How can an impact investor decide on a meaningful carbon price? Various development finance institutions state different internal prices for carbon.[65] The Asian Development Bank (ADB) uses \$43 per tCO_2e (increasing by 2% per year); the European Investment Bank (EIB) uses \$270 per tCO_2e in 2030 (increasing by 6% per year); the European Bank for Reconstruction and Development (EBRD) uses a range from \$50 to \$100 per tCO_2e (increasing by 2.25% per year); and the Network for Greening the Financial System (NGFS) scenarios[66] for central banks and supervisors require carbon prices ranging from \$40 to \$200 per tCO_2e in 2025 and \$60 to \$300 per tCO_2e in 2030. In this report we have taken the 2030 carbon price of the NGFS net zero 2050 (1.5°C) scenarios, which is \$200 per tCO_2e in 2030.[67] The isoquant lines in Figure 15 reflect this carbon price.[68]

As an example of how to interpret the country/technology combinations in Figure *15*, consider solar PV and hydro in Kenya, each with a similar distance to the $\Delta GDP_{net} = 0.25$ isoquant. But solar PV's impact is driven largely by decarbonising the grid, whereas hydro's impact is a mixture of carbon avoidance and economic development impact.

One can rank the country/technology combinations to derive a cross-country ranking of investment opportunities. Although we provide a per country ranking in the country annexes, we caution against taking the results at face value, because they do not include the effect of power imports and exports, nor do they include the forecasted increase of electricity demand. For example, the relatively low impact of CCGT in Mozambique is driven by the fact that it currently has no shortage of power (that is, more power generation does not alleviate power outages). However, the CCGT plant currently under construction will export most of its production to South Africa, and the impact would be more comparable to that OCGT in South Africa (see Section 6.5).

Nevertheless, we think that Figure *15* illustrates how trade-offs between climate and development can be navigated systematically, and we would recommend expanding the methodology to include regional power pools and demand forecasts explicitly. In the next

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[65] Fankhauser, S. et al. (2023) Net zero portfolio targets for development finance institutions: Challenges and solutions. *Global Policy* 14: 716-729. https://doi.org/10.1111/1758-5899.13286

[66] Network for Greening the Financial System (2023).

[67] The divergent net zero scenario, which might be more likely, indicates a price of \$275 in 2030.

[68] For example, when $\Delta GDP = 0$, an avoidance of 500 tCO_2e at \$200/tCO_2e yields $\Delta GDP_{net}/capital\ cost$ = 0.1.

subsections we highlight the most important conclusions that can be drawn from the analysis and some recommendations to expand the methodology.

6.2. The importance of cheap dispatchable power

The results point towards a strong combined impact of CCGT, OCGT and HFO, especially in countries where outages occur frequently (notably South Africa) and in countries where outages occur after sunset (Kenya) or during dry years (Kenya and Zambia). Thermal plants serve as a reliable and easily dispatchable source of power and are therefore useful at reducing the frequency and duration of outages. In some carbon-intensive systems, such as Senegal, investments in CCGT can even have a carbon avoidance effect, because they replace more polluting power plants such as HFO or coal, and therefore can help reduce GHG emissions. Moreover, several countries, including Senegal, Mozambique and Côte d'Ivoire, still have abundant natural gas resources which they are seeking to exploit soon.

This creates a conundrum from the perspective of an investor seeking to maximise impact, especially considering the negative reputation associated with fossil fuel investments. One consideration that should be made when considering new thermal plants is the risk of stranded assets. If the costs of renewable and battery technologies drop sooner than expected, CCGT and OCGT plants will likely become less economically viable. Solar energy combined with battery storage has similar characteristics to CCGT and OCGT, because it provides an energy source that is easily dispatchable and is available throughout the day. In Annex 5 we analyse the impact of Kenhardt power plant, an under-construction solar power plant with battery storage in South Africa. Running the model at 2023 conditions, the plant is expected to have a strong impact on reducing outages, will be neutral in terms of the cost of power, and will strongly reduce GHG emissions.

In terms of a 1 MW investment, solar energy combined with battery storage decreases outages by a little more than OCGT (1,905 vs 1,853 MWh), the next best technology in decreasing outages. However, when adjusted for the capital cost, the impact on GDP and GHG emissions per MW is less than half that of OCGT, and also smaller than that of regular solar PV.

The results of solar with storage (Kenhardt) in Figure *15* cannot be compared directly with solar with storage (EIA), because the latter is based on a relatively smaller battery capacity and more recent, and thus lower cost, estimates that reflect improvements in battery technology and affordability. Nevertheless, the results provide an outlook on the promise that battery storage holds when capital costs continue to drop and therefore the GDP and climate per dollar impact increase. As investments continue to flow into R&D and scaling-up of battery production, innovation is expected to decrease the cost of battery technology further, at which stage it will be able to financially compete and replace thermal peaker plants in the power system.

6.3. The need to diversify energy mixes to cope with volatility in power supply

Hydropower currently comprises the majority of installed renewable capacity in Africa, because it is one of the most abundant and cheapest sources of electricity available. Many countries rely on it for a considerable portion of their electricity output. For example, 88% of total electricity production in Zambia, 69% in Mozambique and 28% in Kenya comes from hydroelectric power. Even in Kenya, a country with a relatively lower reliance on hydropower, outages (in terms of lost load) effectively double between dry and wet years, as can be inferred from the reserve margins in wet and dry years in Figure 23.

Our model points to the fact that hydropower will remain an important source of renewable energy in those countries with favourable conditions, because it has a considerable development and climate impact and provides a relatively stable supply of energy compared to other renewable energy sources.

However, climate change is jeopardising the reliability of hydropower as a stable base load power source. Climate change is expected to increase the frequency and intensity of droughts and floods, which would affect the water levels and flows in rivers and reservoirs. This would reduce the amount of water available for hydropower generation and increase the uncertainty and variability of supply. Climate change could also affect the physical performance and efficiency of hydropower plants. Higher temperatures would increase the evaporation losses from reservoirs and reduce the water density and pressure, which would lower the power output and efficiency of turbines.

The effects of climate change on hydropower availability are already materialising. In 2023, water levels at the Kariba Dam, which provides electricity to Zambia and Zimbabwe, were at an all-time low, and this contributed to widespread load shedding across both countries. Although this was not reflected in the model (the Zambia model is based on 2021 data), the model did reflect the impact of droughts on outages in Kenya in 2021.

The upshot is that countries should diversify their energy mixes to improve reliability and prevent situations such as those that occurred in Zambia and Zimbabwe, especially when they are relying to a great extent on one single source of energy.

Given the increase in outages, the socioeconomic impact of investments in power also substantially increases under dry conditions. In Kenya, the GDP impact of power interventions increases by a factor of 1.8 in dry as compared to wet years. This almost doubling of socioeconomic impact does not sacrifice impact on emissions – renewable plants (solar, wind and geothermal) also reduce GHG emissions by an extra 10% as compared to during wet years.

6.4. The value of cost-reflective prices for power generation

In Zambia, hydropower is not priced realistically. This causes capacity additions of any type to increase the cost of power generation, which causes the model to predict negative GDP impacts. When using the realistic cost of hydropower generation based on average global levelized cost of electricity (LCOE)[69] ($0.06/kWh), the GDP impact of other technologies increases. Although the GDP effect is dominated by the reduction in outages, the GDP impact of a wind power plant increases by 3%, of a CCGT plant by 5%, and of a geothermal plant by 9%. Because solar has a relatively small cost-based GDP effect and no outage-based effect, it increases by 61%. The impact of hydropower is reduced by 11%. If Zambia executes on its glide path to bring tariffs in line with costs, this should incentivise further construction of renewable energy plants.

This points to a deeper problem. Because of the very low variable cost of hydropower and because many dams are old and fully depreciated, in non-market power systems governments often view hydropower plants as a cheap source of base load power. This can lead to depletion

[69] Statista (2024) Global average LCOE of hydropower energy 2010–2022. https://www.statista.com/statistics/799349/lcoe-of-hydropower-worldwide/

of water resources and increase the system's vulnerability to droughts (see Section 6.3).[70] Rather than running hydropower as the (perceived) cheapest power source, it would be more optimal to maximise system benefit per cubic metre of water. This means using hydropower plants for middle and peak loads. In countries that have market-based power systems, hydropower is used in this way.

For example, one of the effects of liberalising the power sector in the Philippines in 2001 was the transformation of the role of hydropower in the electricity system. Before the reform, hydropower was mainly used to provide cheap and stable power to meet the minimum demand. However, this also meant that hydropower plants were often running at low efficiency and wasted water resources. After the reform, hydropower plants had to compete with other generation sources in the wholesale electricity spot market, where prices are determined by supply and demand.[71] This created an incentive for hydropower plants to operate more strategically and maximise their revenues. Instead of providing base load power, hydropower plants started to shift their output to follow the load curve and capture the higher prices during peak periods. This also improved system reliability and flexibility, because hydropower can respond quickly to changes in demand and supply. Additionally, hydropower plants became more efficient in their water usage, because they had to optimise their storage capacity and reservoir management.

6.5. The importance of regional power pools

Regional power pools can enhance the efficiency and reliability of power systems by allowing countries to share their generation resources and balance their supply and demand. Power pools can also reduce the costs of power generation by enabling optimal dispatch of different technologies and promoting economies of scale. Furthermore, power pools can facilitate the integration of VRE sources and improve the resilience of the grid to shocks and uncertainties (as outlined in Section 6.3).

The benefits of regionalisation are not included in Figure 15, which summarises the GDP and GHG impacts when the power systems of the countries operate on a stand-alone basis. The effect of CCGT in Mozambique is a good example. The installed power fleet in Mozambique is sufficient to meet the low power demand and would not need to be expanded in the short run. But a large dispatchable power plant is much needed in the Southern African region, notably in South Africa, where power outages have been going on for a long time. When viewed from this regional perspective, the economic impact of the 450 MW Temane power plant in Mozambique, which is currently under construction by Globeleq, is therefore probably more comparable to the impact of OCGT in South Africa.[72] It would be valuable to extend the methodology put forward in this report to include these regional aspects.

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[70] Another example is the Ghana power crisis in 2015, which was caused by low water levels in the Volta reservoir. The overreliance on artificially low-cost hydropower exposed the need for a more diverse power mix as well as better management of water resources.

[71] Steward Redqueen (2015) Economic impact of IFI investments in power generation in the Philippines. https://jobsanddevelopment.org/wp-content/uploads/2018/04/Report-IFC-Philippines-power-project.pdf

[72] Although the GHG impact of the Temane plant has not been analysed in the regional context, the fact that the South African power pool is dominated by South Africa, which is heavily reliant on coal, makes it likely that the plant will reduce the GHG intensity of the South African power pool.

6.6. The overlooked role of investments in T&D

Although the focus of this report is on power generation, the modelled results for Kenya also show great promise in terms of improving power systems through expanding transmission capacity. Although the analysis was only performed for Kenya, the widespread incidence of T&D failures throughout Africa implies that these findings could be applicable on a broader scale. Improving intra-country and regional transmission can ensure that the existing generation capacity is used to meet existing demand. Additionally, it can help provide resiliency to the grid as reliance on VRE grows. Per Figure 15, expansion of a transmission line to western Kenya is the most capital-efficient intervention of all combinations analysed. Unlike IPP investments, the capital investment needed for a transmission line depends not only on its capacity but also on its length. Of course, as with the IPP interventions, the per MW results do not account for the fact that investments in power are lumpy, and transmission investments are even more lumpy than IPP investments.

Regardless, transmission investments are important throughout Africa, both for removing intra-country bottlenecks and to establish interconnections between countries in order to form functioning regional power pools. Most governments lack the capital to make these investments, and unlocking private sector investment is crucial. Kenya has already initiated public-private partnerships to build transmission lines. BII has recognised this need early and established Gridworks, which is investing in the Amari power transmission line in Uganda. Amari is a pilot for introducing private capital in the country's transmission sector.

6.7. Recommendations

The proposed methodology allows an integrated development and climate impact assessment of IPP investments. This is evidenced by the results of the integrated power and economic modelling for the six countries in this report, which we think are useful in considering investment decisions. Nonetheless, we think the validity of the results can be increased substantially by extending the scope of the model in several of areas. Hence we provide the following five recommendations:

1. **Account for long-run economic effects.** Currently, the methodology considers the short-term response of the private sector. The realism of the method would increase by including the long-run response, which encompasses new firm entry and capital investments that increase capacity and productivity. Whereas the short-run response can be inferred from existing data, quantification of long-run effects, which can be substantially larger, is more tentative and often relies on general equilibrium approaches.
2. **Standardise the transmission methodology in the model.** The current extension of the model simulating transmission effects is specific to Kenya, but many other countries likely face similar outages because of T&D failures. By using Geographic Information System (GIS) and optimisation techniques, the methodology can be standardised. This will lead to a more accurate depiction of the causes and extent of system outages and will allow us to assess the impact of investments in transmission infrastructure in all countries and regions.
3. **Include regional power pools.** Regional power pools are important and can be included in the method once the transmission methodology outlined out in this report (see Section 3.5.1) has been further standardised. The economic development and GHG impacts can then be quantified considering regional interactions.

4. **Make supply constraints more dynamic in the model.** Many factors affect the power supply conditions, for example climatic/hydrologic conditions, fuel prices and forex rates. These can be included in the current methodology, which would allow for scenario analysis under a wider range of circumstances and test the robustness of the results.
5. **Include quantitative ex ante impact assessment when making investment decisions.** This analysis allows us to compare development and climate effects of new investments in the power sector. The study can serve as an objective instrument to inform investment decisions and compare different investment choices in the same geography where multiple choices exist.

Annex 1. Côte d'Ivoire

Côte d'Ivoire – executive summary

Context: Côte d'Ivoire relies primarily on thermal (gas and oil-fired) power (91% of total production), with the remainder of power generation in 2021 coming from hydropower. The government is seeking to massively increase renewable electricity production in the country by 2030, with investments in solar and biomass plants under way.

The government's policy aims for energy self-sufficiency, with a strong focus on expanding its renewable energy portfolio. Côte d'Ivoire not only meets its domestic electricity needs but also exports electricity to neighbouring countries, including Ghana, Burkina Faso, Benin, Togo and Mali, underscoring its role as a pivotal electricity supplier in the region.

Investment with highest economic impact (per unit of capital invested): CCGT.

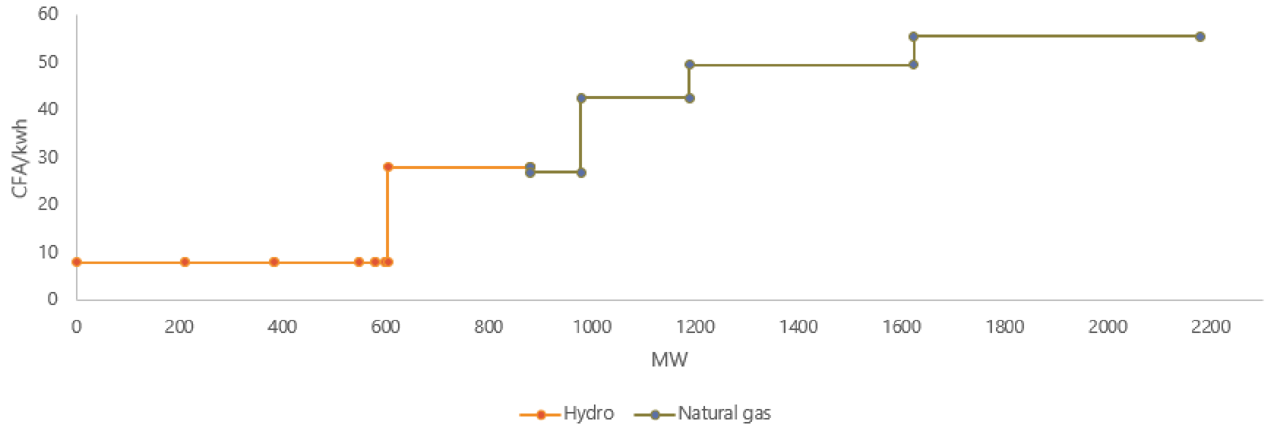
Investment with highest climate impact (per unit of capital invested): Solar PV.

Takeaways:

- Thermal (CCGT) emerges as an economically viable investment in Côte d'Ivoire because it has a GDP/capital cost impact that is 7x that of solar and 10x that of hydropower. It is also by far the most effective at reducing outages (11x that of solar PV and 7x that of hydropower). However, the country's power system is already concentrated in gas-fired thermal power, which is subject to international supply shocks and has a considerable GHG footprint.
- Expanding hydropower and introducing solar power into the grid both appear to be cost-effective ways of reducing the Ivorian grid's GHG intensity. However, their impact on outages, GDP and jobs is marginal compared to that of CCGT.

Power model

Figure 16. Merit order of Côte d'Ivoire[73]



The merit order of Côte d'Ivoire is displayed in Figure 16 and deploys, in order of dispatchment, hydropower and thermal. Hydropower is integrated into the grid first, owing to its low marginal cost, quick start-up, flexibility and non-dispatchability. Thermal power plants then take over to meet demand as necessary, typically running on natural gas and HFO when needed to produce output.

Figure 17. Load curve of Côte d'Ivoire in August (low demand) and December (high demand)

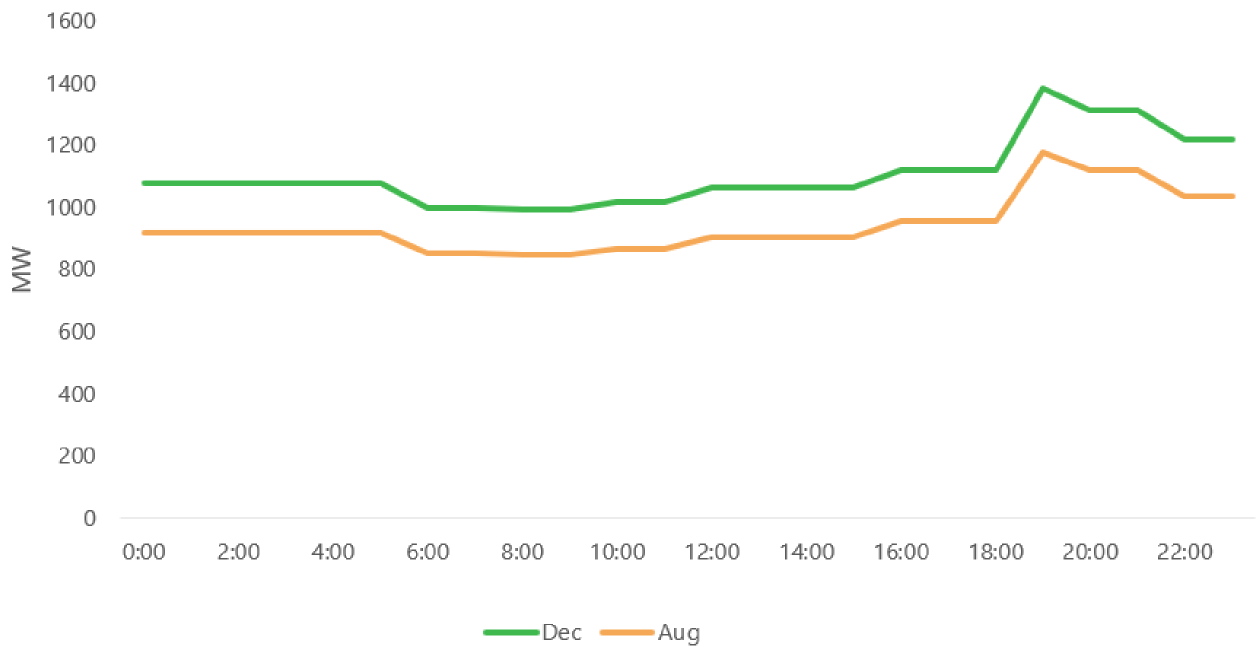


Figure 17 shows load curves for Côte d'Ivoire in August (lowest demand) and December (highest demand). Both load curves show the same pattern across the day, with a low demand during the day and a peak during evening hours.

[73] CFA (see y axis): West African franc.

Figure 18. Reserve margin for Côte d'Ivoire

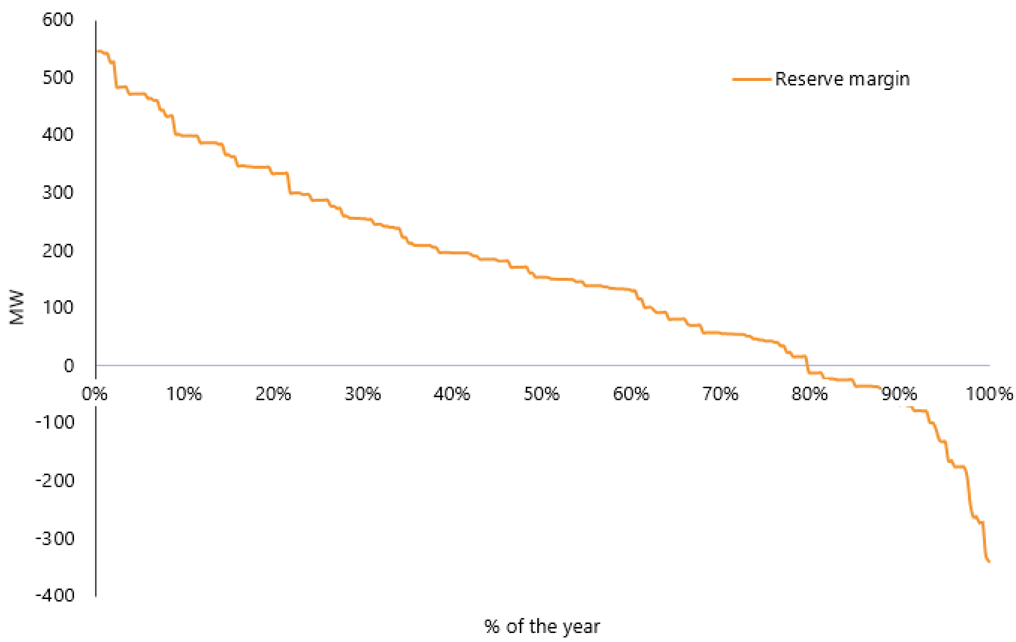


Figure 18 demonstrates the reserve margin for Côte d'Ivoire across the year. For a substantial part of the year the reserve margin is negative, which explains the high incidence of outages in the country. In 2021 power rationing was frequent, owing to a breakdown of the Azito power plant.

Results

Table 12. Key characteristics of the Ivorian power system in the baseline model and actual data

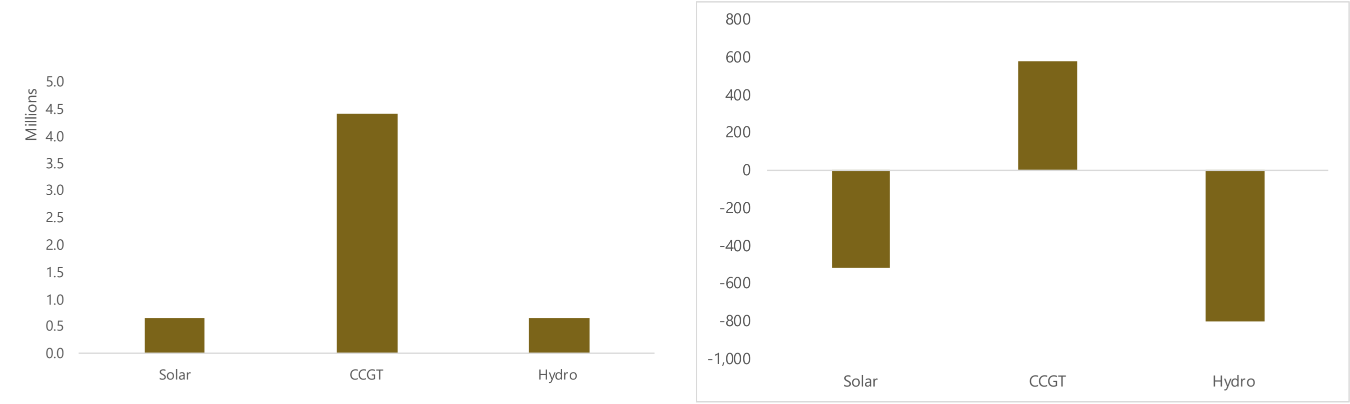
Metric	Power model	Actual data
Power capacity (MW)	2,180	2,180
Power production (TWh)[74]	8.9	8.8
Generation cost of power (CFA/MWh)	46,164	46,275
Number of outages (MWh)	167,000	195,000
GHG intensity (tCO_2e/MWh)	0.44	0.41

To validate the power model, it was applied under conditions that reflected the situation in 2021, which is the latest year for which we have all data available. We looked for four key statistics to confirm that our model matched reality – total production of energy, generation cost, outages, and GHG emissions per tCO_2e.

[74] TWh: Terawatt Hour(s).

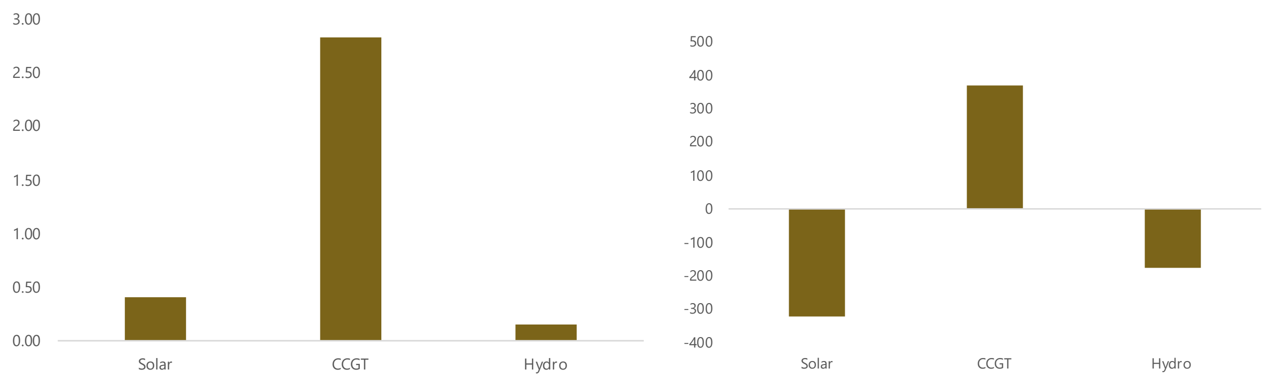
Main takeaways:

Figure 19. Change in GDP (left) and GHG emissions (tCO₂e/y, right) with additional 1 MW of capacity



- Solar power has a small GDP impact because outages occur mainly at night, and its cost effect is limited owing to low utilisation. GHG emissions impact results in a net decrease proportional to its capacity factor.
- CCGT has a large GDP impact because it is reliably available when outages occur and has a high capacity factor and a downward pressure on costs. CCGT increases emissions because it is the only emitting technology currently on the grid, unlike its renewable counterparts.
- Hydropower has a small GDP impact, which is larger than that of solar because of its larger effects on decreasing outages and on power costs. Given its higher capacity factor, hydropower also has a greater decrease on GHG emissions than solar. The downside of hydropower is its high up front capital cost, especially when compared to solar technology.

Figure 20. Change in GDP ($) (left) and GHG emissions (tCO₂e, right) per unit of capital invested



Main takeaways:

- Per dollar invested, solar PV is slightly more effective in reducing outages than hydropower.
- CCGT is the most cost-effective investment to reduce outages, owing to its high output and availability and to its middling capital cost compared to hydropower and solar. However, reliance on fossil fuel imports can be risky considering the volatility of global fuel prices and the impact on forex reserves.
- Per dollar invested, solar PV is more effective in reducing GHG emissions, primarily because of its notably lower capital cost compared to hydropower.

Table 13. Overview of socioeconomic impact results for Côte d'Ivoire

1 MW capacity	Solar PV	CCGT	Hydro
Capital cost ($ million)[75]	1.60	1.56	4.51
Δ GDP ($ million)	0.64	4.41	0.64
Due to Δ outage ($ million)	0.40	4.20	0.45
Due to Δ power cost ($ million)	0.24	0.21	0.19
Δ GHG emissions (tCO2e/y)	-518	577	-808
Δ formal jobs	37	259	37
Δ GDP/capital cost ($/$)	0.46	2.76	0.18
Δ GHG emissions/capital cost (tCO2e/y/$ million)	-324	370	-179
Δ formal jobs/capital cost (per $ million)	23	166	8

Table 14. Climate-development nexus ranking of combinations $200 per tCO_2e. All impacts are calculated on an annual basis

Country	Technology	Δ GDP/capital costs ($ million /$ million)	Δ GHG/capital costs (tCO_2e/$ million)	Δ GDP_{net}/capital costs ($ million impact / $ million)[76]
Côte d'Ivoire	CCGT	2.83	370	2.76
Côte d'Ivoire	Solar PV	0.31	-324	0.46
Côte d'Ivoire	Hydropower	0.18	-194	0.18

Sources

Costs and generation

- Overall and plant-level data on variable and fixed costs, IPP tariffs, energy purchases and generated power was obtained from CIE's 2021 annual report.

[75] U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

[76] This score is calculated by aggregating the economic and climate impact. The GHG impact was converted into an economic impact by using a carbon price of $200/$tCO_2e$.

Availability

- Available supply of thermal plants was determined based on annual averages provided by CIE's 2021 annual report.
- Available supply of solar power was calculated based on data from the Global Solar Atlas.
- Hydrological data to determine availability of hydropower plants was taken from CIE's 2021 annual report, which also provides estimates for wet, dry and normal years.
- GHG intensities were determined by combining fuel inputs and data on emission factors per technology type from the Greenhouse Gas Protocol's cross-sector tools.

Demand

- Seasonal variations in demand were determined using peak demand data from CIE's annual reports.
- The load curve of Côte d'Ivoire was established based on an Ivorian load curve profile sourced from IRENA (2018) *IRENA Planning and Prospects for Renewable Power: West Africa*.

Macroeconomic data

- Labour data was sourced from the International Labour Organization (ILO) and Women in Informal Employment: Globalizing and Organizing (WIEGO) *Statistical Brief No. 31* (2022) for estimates of the share of the informal economy as a percentage of GDP.
- GDP data was sourced from the World Bank national accounts dataset.

Annex 2. Kenya

Kenya – executive summary

Context: Kenya's energy system is characterised by a diversified mix of geothermal (29%), hydropower (28%), thermal (23%) and renewable energy (20%). Thermal energy is mainly used to meet peak demand. Prolonged droughts associated with climate change have put pressure on the availability of hydropower, and this has contributed to power shortages and increased the use of HFO.

Investment with highest economic impact (per unit of capital invested): HFO.

Investment with highest climate impact (per unit of capital invested): Solar PV.[77]

Takeaways:

- HFO currently emerges as the appealing investment in Kenya because it is highly effective in reducing outages, which offsets the negative GHG effect. But given its similar cost base and dispatch profile, an environmentally better option may be an OCGT, although it was not explicitly analysed.
- Geothermal is an attractive investment as well, owing to its combined positive impact on increasing GDP and curbing GHG emissions. However, it cannot be applied consistently across the country.
- Solar PV does not support reducing outages, because outages do not occur throughout the day. This translates into a limited GDP effect. Nevertheless, it remains the most cost-efficient technology to reduce GHG emissions.

[77] Although transmission has a higher economic and climate impact per unit of capital invested, the capital costs are highly context-specific (for example length, type of terrain) and therefore not as generalisable.

Power model

Figure 21. Merit order of Kenya

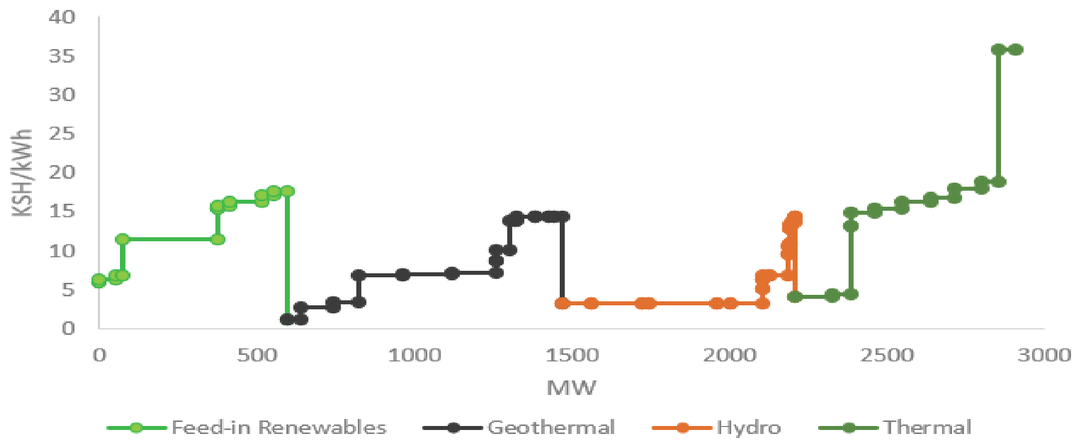


Figure 21 presents the modelled merit order for Kenya. Renewables, being non-dispatchable, integrate into the grid first. Despite higher average costs, geothermal energy takes precedence over hydropower because of the reduced availability and conservation of hydropower and water resources during dry years. Renewables and geothermal serve as the base load power sources, typically remaining online at all times. Thermal power plants are utilised to address peak load demands.

Figure 22. Load curve of Kenya in June, December and on average

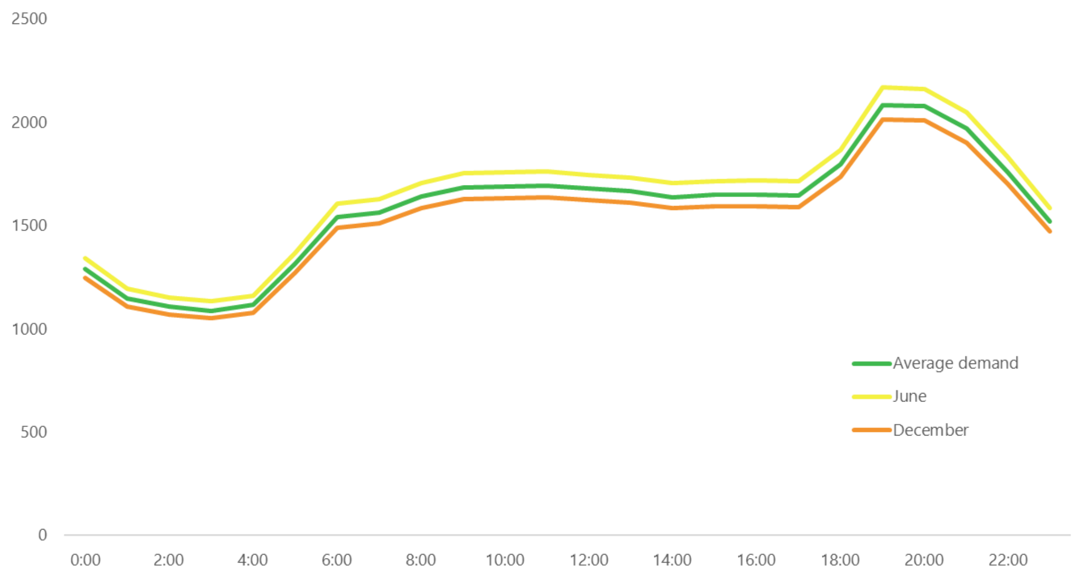


Figure 22 shows load curves for Kenya in June, December and on average. All load curves show a similar pattern, with a gradual increase in the early hours and a sharp peak in demand between 7:00pm and 9:00pm. Peak demand is 7% lower in December than in June.

Figure 23. Reserve margin for Kenya

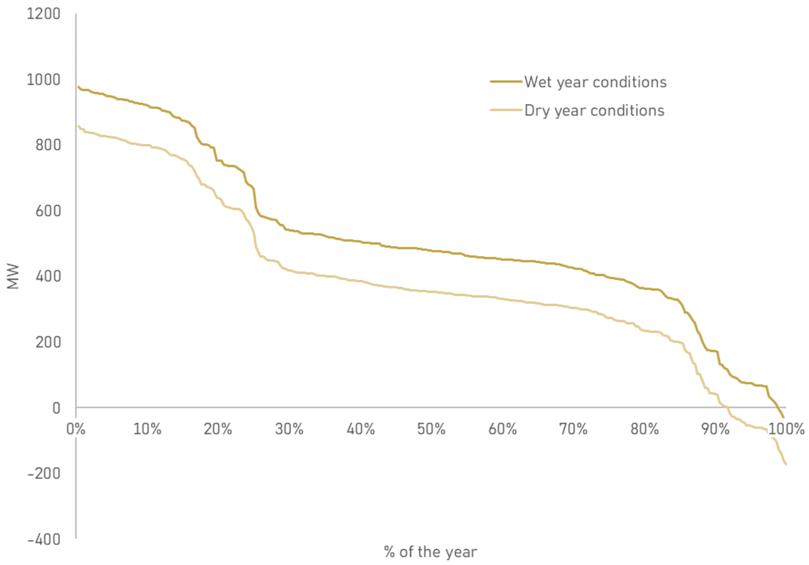


Figure 23 shows the reserve margin in Kenya in wet and dry years. The reserve margin looks at the difference between supply and demand throughout the year and is ordered by magnitude of difference. It gives an indication of how well the power supply can keep up with demand. In wet years the reserve margin is only negative for approximately 1% of the year, and in dry years this rises to approximately 8% of the year.

Results

Table 15. Key characteristics of the power system in the baseline model and actual data

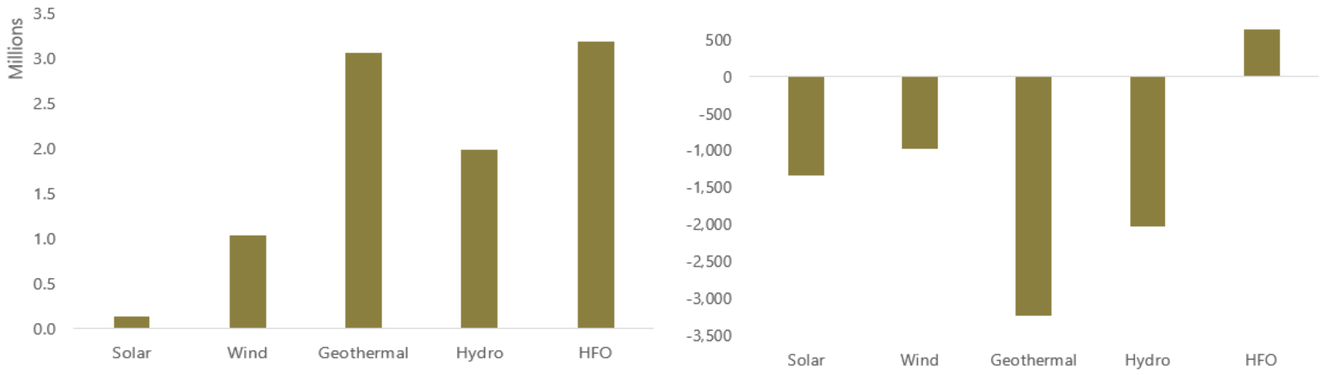
Metric	Power model	Actual data
Power capacity (MW)	2,979	2,979
Power production (TWh)	12.4	12.7
Cost of generation (KSh/MWh)	9,751	9,816
Number of outages (MWh)	93,392	N.A.[78]
Outages (% of time)	0.7	0.879
GHG intensity (tCO2e/MWh)	0.14	0.14

[78] Although SAIDI & SAIFI outage data is collected by KPLC, sensitivities around the data make it difficult to obtain.

[79] Taneja, J. (2017) Measuring Electricity Reliability in Kenya.

To validate the power model, it was programmed under conditions that reflected the 2021 financial year, which is the latest year for which we have all data available. We looked for four key statistics to confirm that our model matched reality – total production of energy, generation cost, outages, and GHG emissions per tCO_2e.

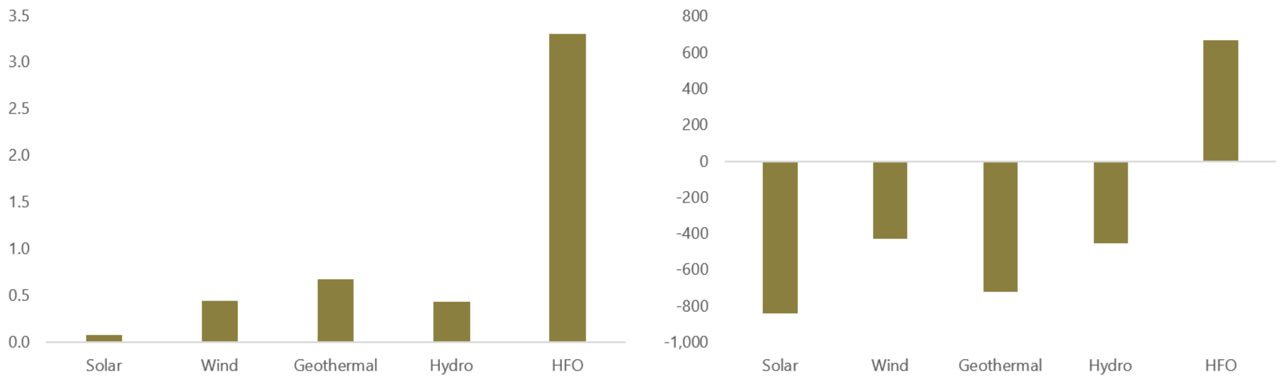
Figure 24. Annual change in GDP (left) and GHG emissions (tCO_2e/y, right) with additional 1 MW of capacity



Main takeaways:

- Solar power has a small GDP impact, because outages occur in the evening hours, and the cost effect is limited because of low utilisation. GHG emissions are proportional to its capacity factor.
- Geothermal has a large GDP impact, because it is available when outages occur and has a substantial downward pressure on costs. Geothermal reduces more GHG emissions than hydropower, owing to higher capacity utilisation. The disadvantage of geothermal is that it can only be utilised in places where the conditions are right.
- HFO has a large GDP impact, because it is available exactly when outages occur. However, it also increases GHG emissions proportional to its use.

Figure 25. Annual change in GDP ($, left) and GHG emissions (tCO_2e, right) per unit of capital invested



Main takeaways:

- Per dollar invested, wind is substantially more effective than solar in reducing outages in places where geothermal is not possible.
- HFO is, by a large margin, the most cost-effective investment to reduce outages, owing to its dispatchable character and low capital costs. However, investing in HFO means relying on fossil fuel imports, which can be risky considering the volatility of global fuel prices and the impact on forex reserves.

- Per dollar invested, solar, followed by geothermal, is most effective in reducing GHG emissions and is about twice as effective as wind and hydropower.

Table 16. Overview of socioeconomic impact results for Kenya

1 MW capacity	Solar	Wind	Geo-thermal	Hydro	HFO
Capital cost ($ million)[80]	1.60	2.29	4.50	4.51	0.96
Δ GDP ($ million)	0.12	1.03	3.01	1.97	3.17
Due to Δ outage ($ million)	0.00	0.98	2.87	1.8	3.2
Due to Δ power cost ($ million)	0.12	0.05	0.18	0.16	-0.05
Δ GHG emissions (tCO2e/y)	-1,342	-978	-3,237	-2,040	642
Δ formal jobs	6	53	157	102	164
Δ GDP/capital cost ($/$)	0.04	0.26	0.39	0.17	1.90
Δ GHG emissions/capital cost (tCO2e/y/$ million)	-835	-418	-705	-292	384
Δ formal jobs/capital cost (per $ million)	2	11	16	7	79

Table 17. Climate–development nexus ranking of all combinations using $200 per tCO_2e. All impacts are calculated on an annual basis

Country	Technology	Δ GDP/capital costs ($ million /$ million)	Δ GHG/capital costs (tCO_2e/$ million)	Δ GDP_{net}/capital costs ($ million impact / $ million)[81]
Kenya	Transmission	7.23	-953[82]	7.42
Kenya	HFO	1.90	384	1.82
Kenya	Geothermal	0.39	-705	0.53
Kenya	Wind	0.26	-418	0.34
Kenya	Solar PV (Malindi)	0.12	-1076	0.34
Kenya	Hydropower	0.17	-292	0.23
Kenya	Solar PV	0.04	-835	0.21

[80] U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

[81] This score is calculated by aggregating the economic and climate impact. The GHG impact was converted into an economic impact by using a carbon price of $200/$tCO_2e$.

[82] The climate impact of transmission is due to the fact that more polluting HFO plants are not required to run because it allows renewable energy from elsewhere in Kenya (for example geothermal, wind) to reach the Western Region.

Impact of Malindi

Malindi is a 40 MW_{AC}[84] solar plant managed in Eastern Kenya, majority-owned by Globeleq (which is majority-owned by BII). The objective was to run the model under 2018 conditions, when Malindi was planned, and 2022 conditions, when Malindi came online, to adjudge what the impact of the solar was, matching parameters of hydrology, cost of fuel, exchange rates and demand. Malindi was then 'removed' from the grid to quantify its effects on outages, generation cost and GHG emissions by comparing against the counterfactual.

The model found that Malindi did contribute towards reducing GHG emissions and reducing the cost of power and was thus effective at decarbonising the grid cheaply.

However, since 2018 Kenya has successfully added more generation capacity to the grid. As such, outages in Kenya typically take place at night and are more common in the Western Region, which means that in 2022 the Malindi plant effectively had no impact on outages caused by supply shortages.

Table 18. Overview of socioeconomic impact results for Malindi

40 MW capacity	2018 conditions	2022 conditions
Capital cost ($ million)83	69	69
Δ outages (MWh)	-83	0
Δ power cost (%)	-1.3%	-2.0%
Δ GHG emissions (%)	-3.8%	-3.6%
Δ GHG emissions (tCO2e/y)	-74,971	-74,273
Δ GDP ($ million)	5.90	8.38
Δ formal jobs	246	350
Δ GDP/capital cost ($/$)	0.09	0.12
Δ GHG emissions/capital cost (tCO2e/y/$)	-1087	-1076
Δ formal jobs/capital cost (per $)	3.6	3.4

Nonetheless, the reduction in the cost of power is expected to be transferred to firms, resulting in a GDP increase of $8.3 million. This results in an economic payback time of eight years. The formal employment supported is 350 jobs.

[83] U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

[84] MW_{AC}: Megawatts (Alternating Current).

Sources

Costs and generation

- Overall and plant-level data on cost and generated power was obtained from KPLC's annual reports from 2018 to 2023.
- Confirmatory details on IPP tariffs for renewables and capacity charges for thermal plants were taken from the 2021 Report by the Presidential Taskforce on PPAs.
- Details on currency effects were taken from the 2018 Feasibility Study on Local Currency-Denominated Tariffs for Kenyan PPAs by GuarantCo, Kenya Power, the Kenyan Ministry of Energy, the Energy Regulatory Commission, Dalberg Advisors, and Leadwood Energy.
- The link between consumer tariffs and cost of power was established by looking at historical tariff data[85] and through qualitative research and interviews.

Availability

- Hydrological data to determine the availability of hydropower plants was taken from Kenya's 2021 Least Cost Power Development Plan.
- Available supply of solar power was calculated based on data from the Global Solar Atlas.
- Available supply of wind power was calculated based on data from the NASA Prediction of Worldwide Energy Resources (POWER) project.
- GHG intensities were determined using submissions to the United Nations Framework Convention on Climate Change's Clean Development Mechanism (CDM).
- Transmission data was obtained from the Kenyan Energy and Petroleum Regulatory Authority's portal for Renewable Energy.

Demand

- Seasonal variations in demand were determined using peak demand data from KPLC's annual reports and the 2021 Report by the Presidential Taskforce on PPAs.
- Additional details on daily and seasonal load variations were based on the work of Irungu, D.W. (2016) *Simulation of the Future Electricity Demand and Supply in Kenya using the Long-Range Energy Alternative Planning System* and Hart, C. & Wright, J. G. (2016) *Impact of Novel and Disruptive Approaches/Technologies on a Distribution Utility: A Kenyan Case Study*.

Macroeconomic data

- Labour data was sourced from the Kenya National Bureau of Statistics.
- GDP data was sourced from the World Bank national accounts dataset.

[85] On https://www.stimatracker.com/

Annex 3. Mozambique

Mozambique – executive summary

Context: Mozambique's energy system is characterised by a diversified mix of hydropower (57%), thermal (37%) and renewable energy (5%). In terms of renewable energy, Mozambique produces solar energy (3%), as well as biomass energy (2%) through sugar companies operating in the country. The country's reliance on hydropower exposes it to climatic variability, with droughts impacting water availability and consequently reducing hydropower output. During such periods, Mozambique resorts to thermal power generation to meet electricity demand.

Investment with highest economic impact (per unit of capital invested): CCGT.

Investment with highest climate impact (per unit of capital invested): Geothermal.

Takeaways:

- Geothermal emerges as the most appealing investment in Mozambique, owing to its combined impact on increasing GDP and curbing GHG emissions.
- Solar PV is a highly cost-efficient technology to reduce GHG emissions. The limited outages experienced by Mozambique largely take place at night, and solar PV thus does not help reduce outages, translating into a limited GDP effect.
- CCGT is highly effective in reducing outages across the night and therefore has the highest GDP effect per unit of capital invested.

Power model

Figure 26. Merit order of Mozambique[86]

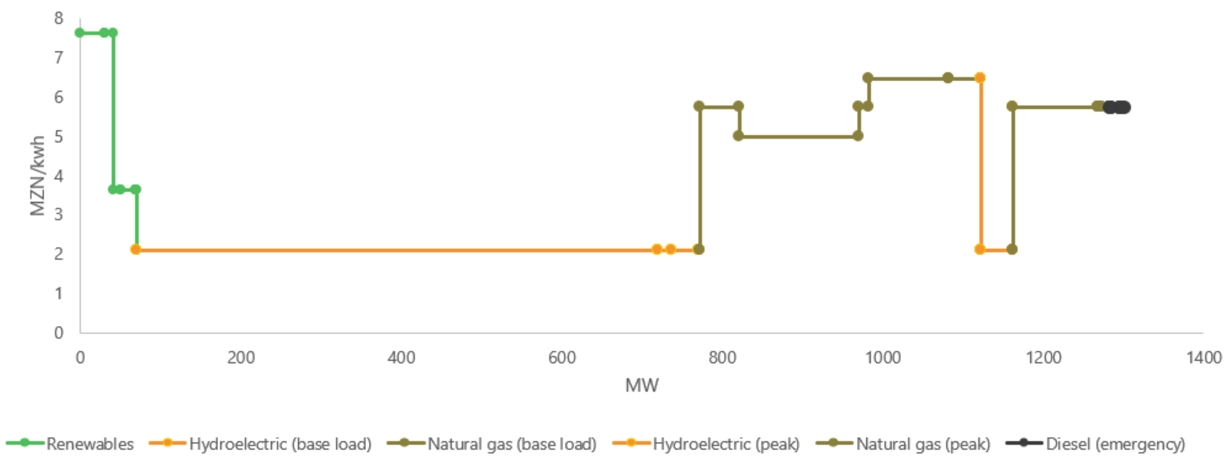


Figure 26 presents the modelled merit order for Mozambique. Feed-in renewables, because of their non-dispatchable nature, are integrated into the grid first. Hydroelectric and thermal plants are deployed after that. There are a number of hydropower and gas-fuelled plants that are used as peaker plants; diesel-fuelled plants are only used for emergencies.

Figure 27. Load curve of Mozambique in January, June and on average

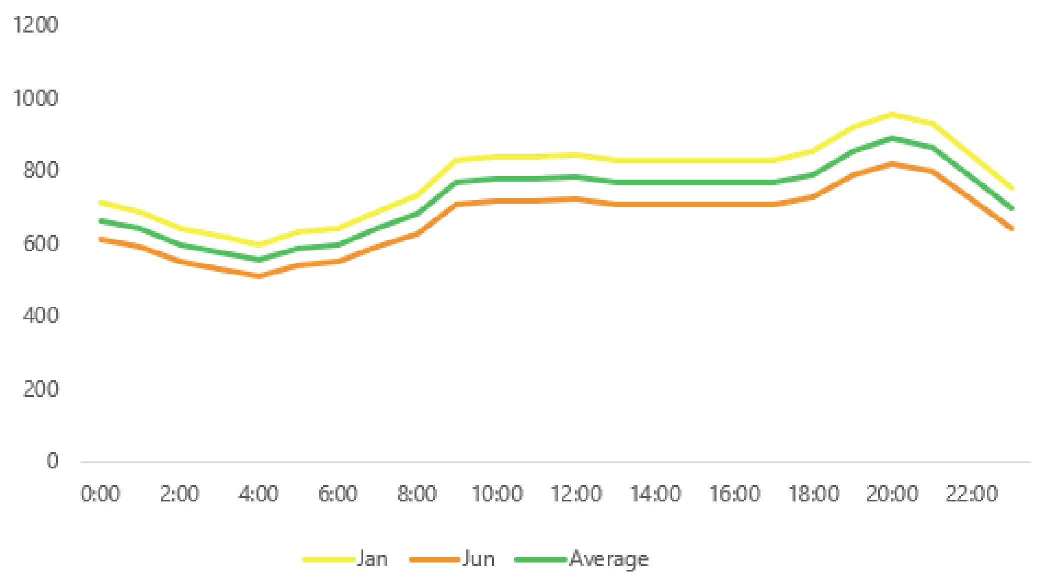


Figure 27 shows load curves for Mozambique in January, June and on average. All load curves show a similar pattern, with a gradual increase in the early hours of the day and a sharp peak in demand between 7:00pm and 9:00pm. Peak demand is 14% lower in June than in January.

[86] MZN (see y axis): Mozambican Metical.

Figure 28. Reserve margin for Mozambique

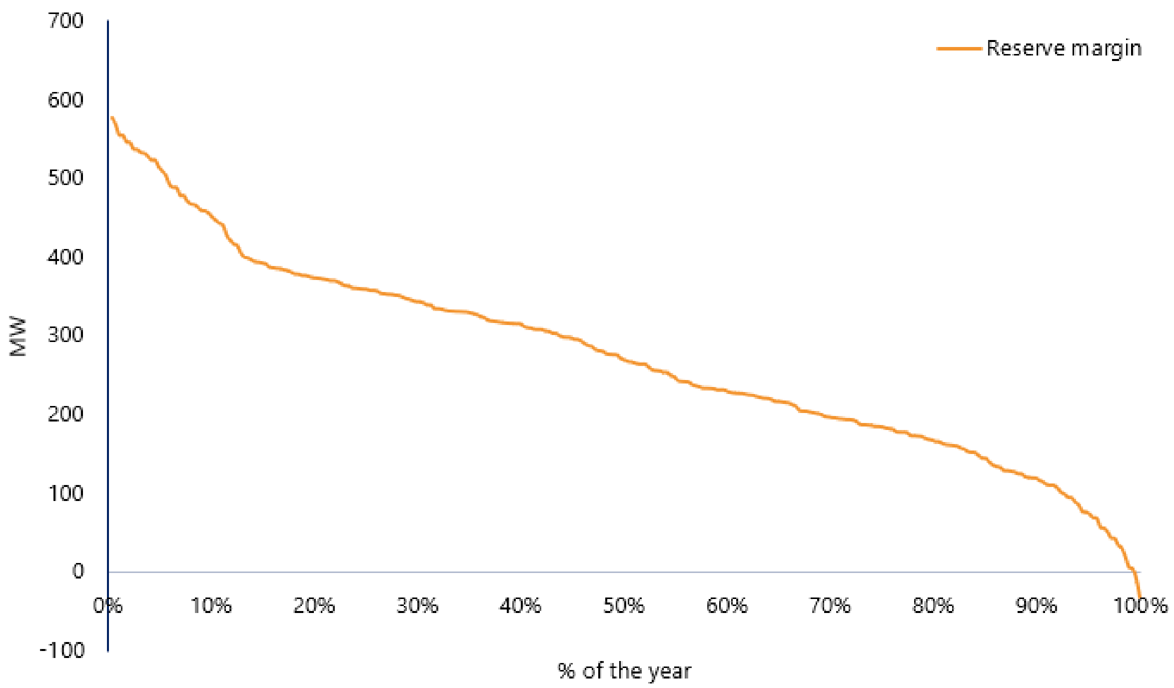


Figure 28 demonstrates the reserve margin for Mozambique. The reserve margin is positive for almost the entire year, which shows the resilience of Mozambique's power system and explains the low incidence of outages.

Results

Table 19. Key characteristics of the Mozambican power system in the baseline model and actual data

Metric	Power model	Actual data
Power capacity (MW)	2,879	2,879
Power production (TWh)	9.0	8.1
Total costs of electricity production, transmission & distribution (MZN billion)	28.76	30.83[87]
Number of outages (hours)	60	49
GHG intensity (tCO_2e/MWh)	0.15	0.13[88]

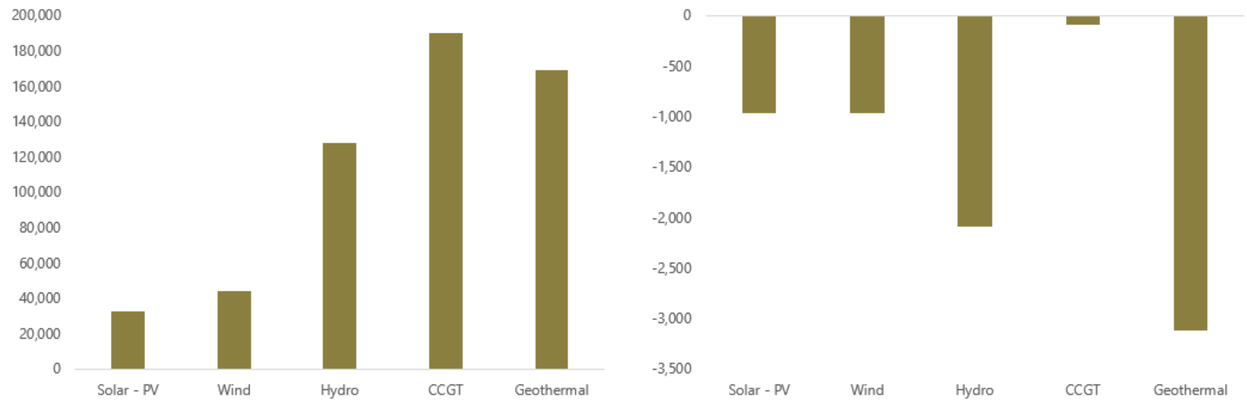
To validate the power model, it was programmed under conditions that reflected the 2022 financial year, which is the latest year for which we have all data available. We looked for four

[87] EDM, Annual Report (2022).

[88] Ritchie, H., Rosado, P. and Roser, M. (2023) 'Energy'. https://ourworldindata.org/energy. Latest available estimate from 2021.

key statistics to confirm that our model matched reality – total production of energy, generation cost, outages, and GHG emissions per tCO_2e.

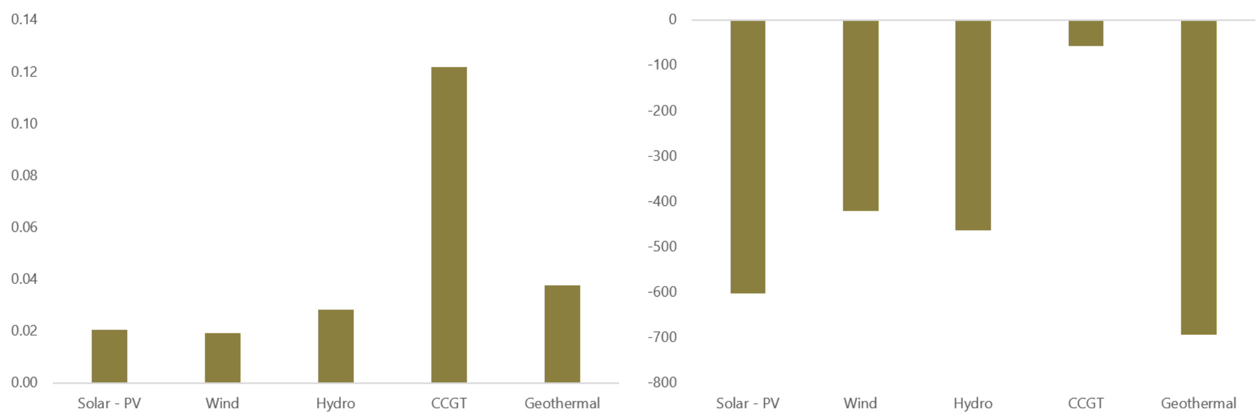
Figure 29. Annual change in GDP (left) and GHG emissions (tCO_2e/y, right) with additional 1 MW of capacity



Main takeaways:

- CCGT exhibits the most significant GDP impact per 1 MW of added capacity, attributed to its high availability factor and cost-reducing attributes. This is followed by geothermal, hydropower and wind, which have decreasing availability factors.
- Regarding GHG impact, geothermal proves to be the most efficient technology per 1 MW of added capacity, thanks to its high capacity factor. This is followed by hydropower and other renewables, such as wind and solar, which have lower capacity factors.

Figure 30. Annual change in GDP ($, left) and GHG emissions (tCO_2e, right) per unit of capital invested



Main takeaways:

- CCGT is the most cost-effective investment to reduce outages, owing to its dispatchable character.
- Per dollar invested, wind and solar are equally effective in reducing outages in places where geothermal or hydropower are not possible.
- Per dollar invested, geothermal is the most effective in reducing GHG emissions, followed by hydropower and solar.
- The observed changes in GDP do not account for Mozambique's potential to export its electricity surplus to South Africa, such as that of the newly constructed Temane power

plant, which was co-financed by BII. As such, there may be a substantially larger impact on GDP when considering this regional component.

Table 20. Overview of socioeconomic impact results for Mozambique

1 MW capacity	Solar PV	Wind	Hydro	CCGT	Geothermal
Capital cost ($ million)[89]	1.60	2.29	4.51	1.56	4.50
Δ GDP ($ million)	0.03	0.04	0.13	0.19	0.17
Due to Δ outage ($ million)	0	0.06	0.08	0.20	0.18
Due to Δ power cost ($ million)	0.03	-0.02	0.05	-0.01	-0.01
Δ GHG emissions (tCO2e/y)	-965	-965	-2,089	-90	-3,120
Δ formal jobs	3	4	11	17	15
Δ GDP/capital cost ($/$)	0.02	0.02	0.03	0.12	0.04
Δ GHG emissions/capital cost (tCO2e/y/$)	-603	-421	-463	-57	-693
Δ Formal jobs/capital cost (per $)	2	2	2	11	3

Table 21. Climate-development nexus ranking of all combinations in using $200 per tCO_2e. All impacts are calculated on an annual basis.

Country	Technology	Δ GDP/capital costs ($ million /$ million)	Δ GHG/capital costs (tCO_2e/$ million)	Δ GDP_{net}/capital costs ($ million impact / $ million)[90]
Mozambique	Geothermal	0.04	-693	0.18
Mozambique	Solar PV	0.02	-603	0.14
Mozambique	CCGT	0.12	-57	0.13
Mozambique	Hydropower	0.03	-463	0.12
Mozambique	Wind	0.02	-421	0.10

[89] U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

[90] This score is calculated by aggregating the economic and climate impact. The GHG impact was converted into an economic impact by using a carbon price of $200/$tCO_2e$.

Sources

Costs and generation

- Overall and plant-level data on cost and generated power was obtained from EDM's 2022 annual report.
- Details on tariffs were obtained from Salite, D, et al. (2021) *Electricity Access in Mozambique: A Critical Policy Analysis of Investment, Service Reliability and Social Sustainability*.

Availability

- Hydrological data to determine availability of hydropower plants was taken from the African Hydropower Atlas.
- Available supply of solar power was calculated based on data from the Global Solar Atlas.
- Available supply of wind power was calculated based on data from the NASA POWER project.
- GHG intensities were determined using information from the EIA and the GHG Protocol.
- Transmission data was obtained from EDM's 2022 annual report.

Demand

- Seasonal variations in demand were taken from EDM's 2020 annual statistics and adjusted based on 2022 peak demand data from EDM's 2022 annual report.

Macroeconomic data

- Labour data was sourced from the ILO dataset.
- GDP data was sourced from the World Bank national accounts dataset.

Annex 4. Senegal

Senegal – executive summary

Context: The country relies primarily on thermal power (79% of total production). Senegal's energy strategy focuses on gas-to-power conversion as the country is poised to become a major gas producer. Other energy sources include hydropower (8%), wind (7%) and solar PV (6%). There is significant potential for renewable energies considering Senegal's favourable climatic conditions.

Investment with highest economic impact (per unit of capital invested): HFO.

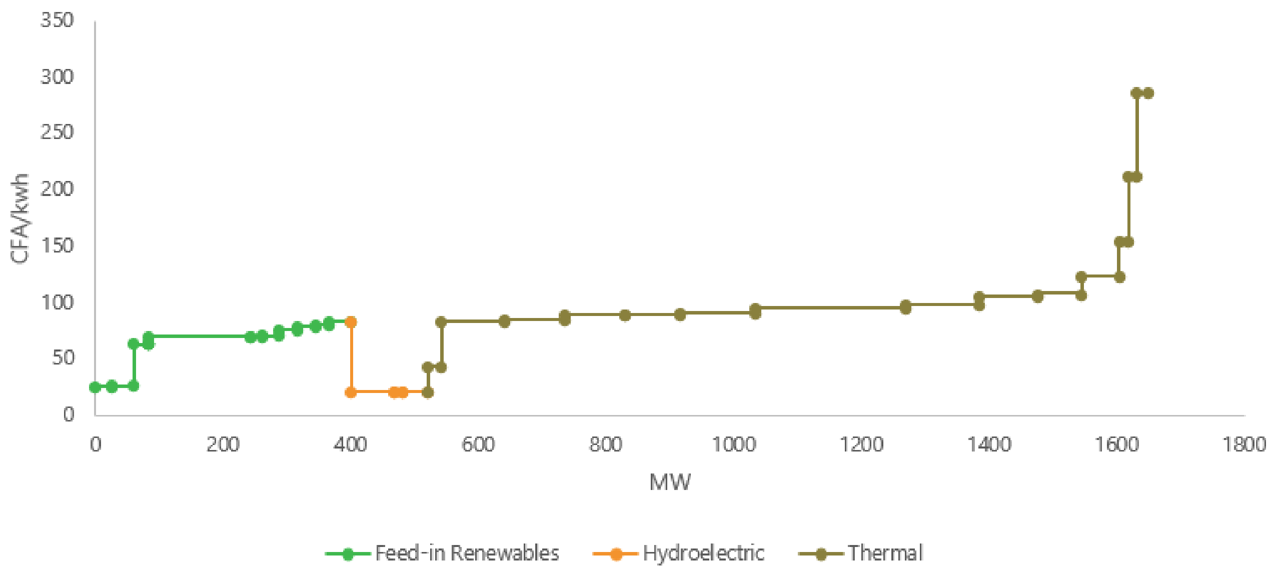
Investment with highest climate impact (per unit of capital invested): CCGT.

Takeaways:

- Given the absence of power outages in Senegal, the impact on GDP is solely driven by price dynamics and is therefore limited compared to other countries.
- Surprisingly, CCGT emerges as the most attractive investment in terms of its GHG effect. This has to do with a combination of CCGT's high availability factor, relative low costs, and Senegal's high carbon intensity, leading to a higher decarbonisation of the grid than renewables.
- CCGT also has the highest net GDP impact, although HFO has a slightly higher economic impact, with the positive GHG impact of CCGT making up for the difference.

Power model

Figure 31. Merit order of Senegal



The merit order of Senegal deploys, in order of dispatchment, feed-in renewables, hydroelectric and thermal plants. A number of ageing gas and diesel-fuelled plants are used as peaker plants, which cause an upward cost pressure on the power system because of high fuel costs.

Figure 32. Load curve of Senegal in January (low demand) and October (high demand)

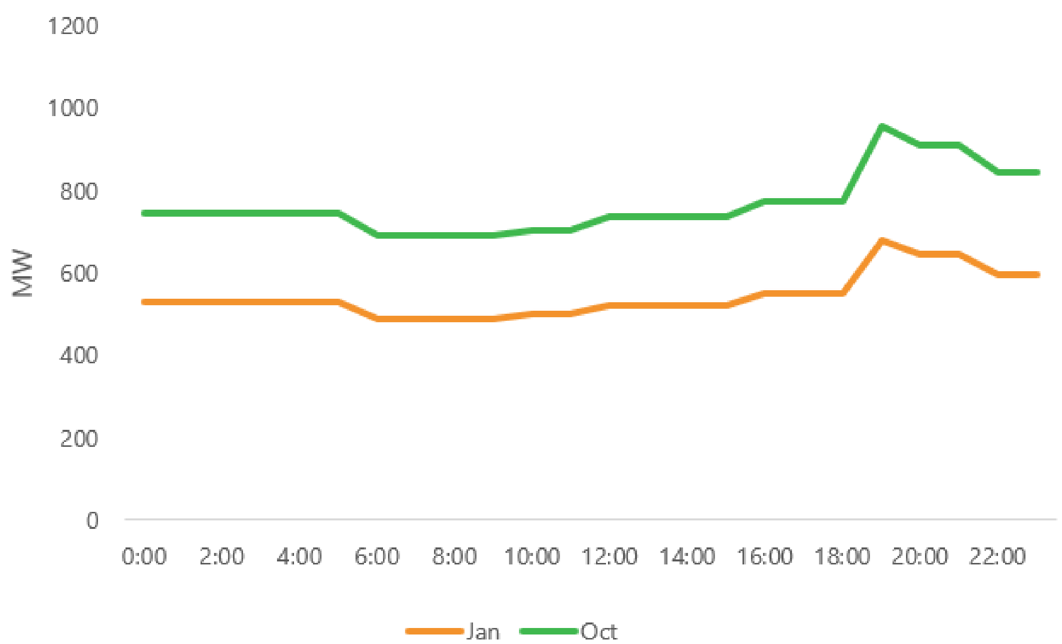


Figure 32 shows load curves for Senegal in January (lowest demand) and October (highest demand). Both load curves show a similar pattern, with a low demand during the day and a peak during evening hours.

Figure 33. Reserve margin for Senegal

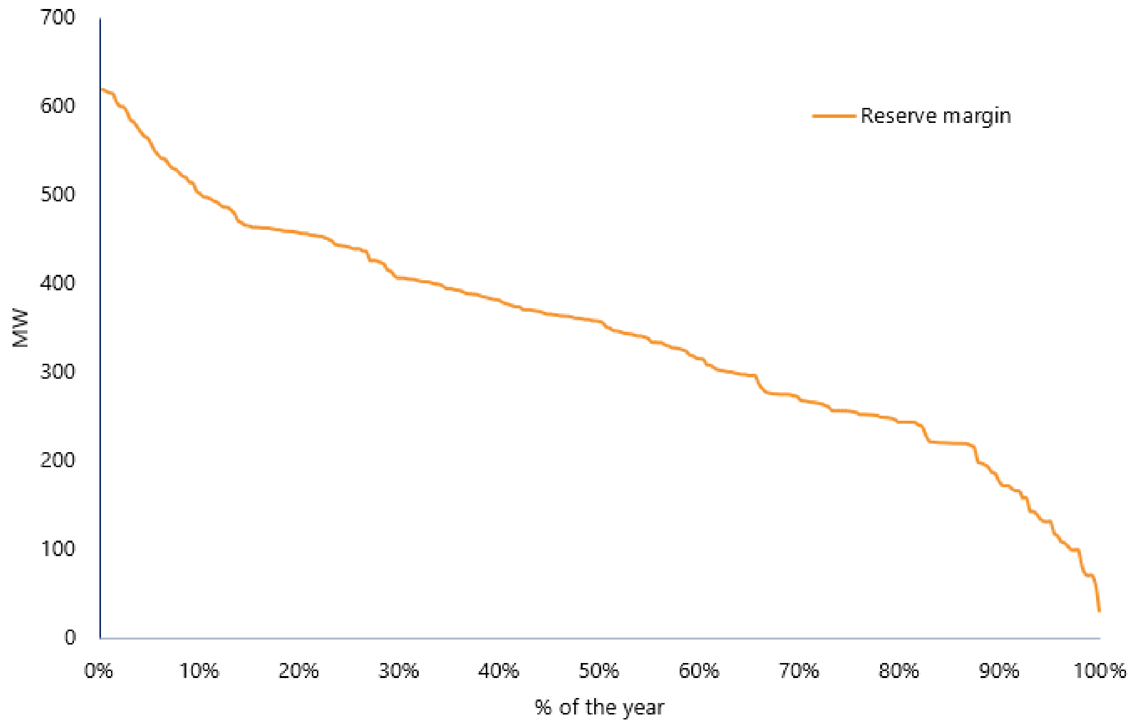


Figure 33 demonstrates the reserve margin for Senegal. The curve is consistently positive, which shows the resilience of Senegal's power system and explains the low incidence of outages.

Results

Table 22. Key characteristics of the Senegalese power system in the baseline model and actual data

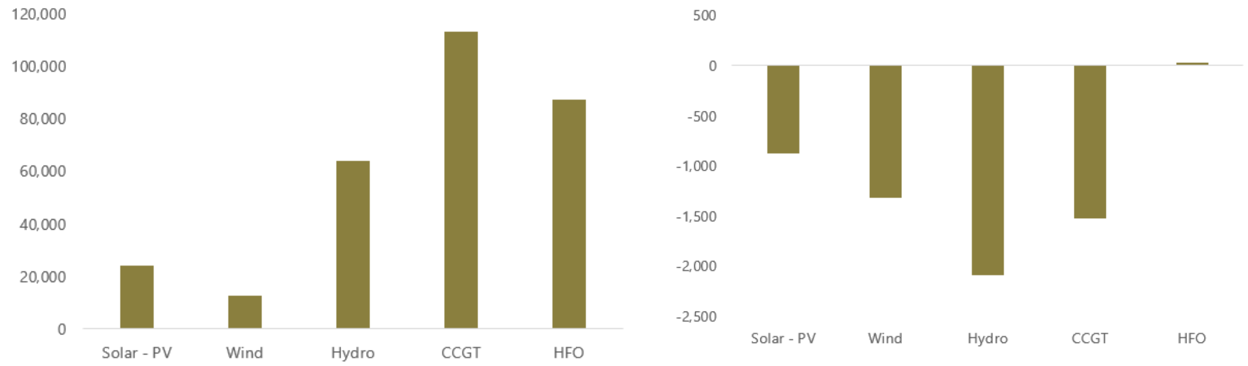
Metric	Power model	Actual data
Power capacity (MW)	1,670	1,660
Power production (TWh)	4.8	4.9
Generation cost of power (CFA/MWh)	91.2	91.5
Number of outages (MWh)	-	2,900[91]
GHG intensity (tCO_2e/MWh)	0.51	0.52[92]

To validate the power model, it was programmed under conditions that reflected the 2022 financial year, which is the latest year for which we have all the data available. We looked for four key statistics to confirm that our model matched reality – total production of energy, generation cost, outages, and GHG emissions per tCO_2e.

[91] Outages occurred because of fuel shortages in June at several thermal plants. Given the idiosyncratic nature of the events, this is not accounted for in the model.

[92] Ritchie, H., Rosado, P. and Roser, M. (2023) 'Energy'. https://ourworldindata.org/energy. Latest available estimate from 2021.

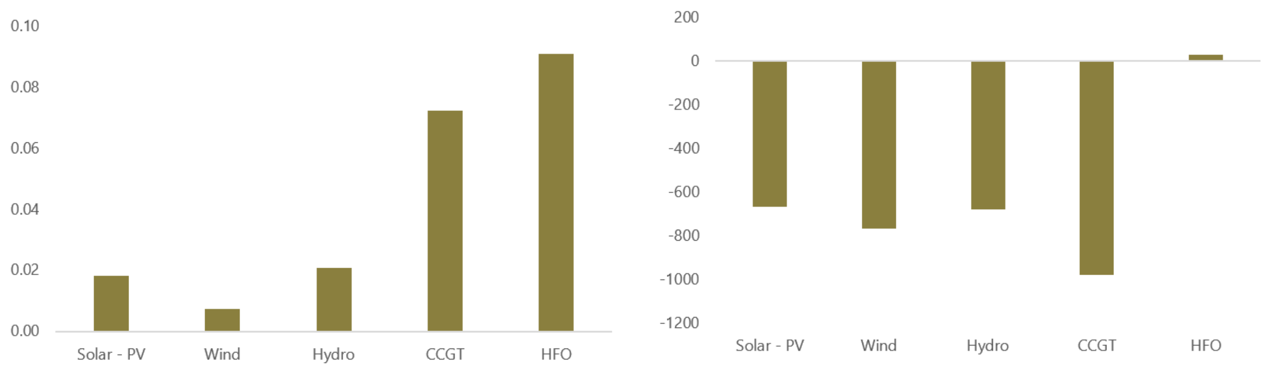
Figure 34. Annual change in GDP (left) and GHG emissions (tCO_2e/y, right) with additional 1 MW of capacity



Main takeaways:

- Given the absence of power outages in the baseline scenario for Senegal, the impact on GDP is solely influenced by price dynamics, resulting in a comparatively limited effect compared to other countries in the study.
- CCGT exhibits the most significant GDP impact per 1 MW of added capacity, attributed to its high availability factor and cost-reducing attributes. This is followed by HFO and hydropower. Renewables show a limited GDP impact, primarily owing to lower availability factors.
- Regarding GHG impact, hydropower proves to be the most efficient technology per 1 MW of added capacity, thanks to its high capacity factor.
- Surprisingly, CCGT also contributes substantially to GHG reduction. This can be explained by Senegal's heavy reliance on HFO, which emits 60% more tCO_2e/kWh than CCGT. Because CCGT has a higher capacity factor than renewables and replaces HFO during peak hours when solar PV is unavailable, it proves to be more effective than solar in reducing GHG emissions in Senegal. Notably, CCGT surpasses solar PV and wind in impact because of its higher availability factor.

Figure 35. Change in GDP ($, left) and GHG emissions (tCO_2e, right) per unit of capital invested



Main takeaways:

- When assessing the economic impact per unit of capital, CCGT and HFO stand out as significantly more appealing compared to other technologies. Their impact is about three times the next most attractive option (hydropower). Solar PV and wind have a limited effect on GDP.
- In terms of GHG emissions per unit of capital invested, CCGT emerges as the most favourable investment, surpassing hydropower because of its lower capital cost. Surprisingly, its GHG

effect is nearly double that of solar PV and wind. The higher availability factors of CCGT, and the fact that it can replace HFO during peak hours (when solar PV is not online), more than compensate for its higher GHG intensity compared to renewables.

Table 23. Overview of socioeconomic impact results for Senegal

1 MW capacity	Solar	Wind	Hydro	CCGT	HFO
Capital cost ($ million)[93]	1.60	2.29	4.51	1.56	0.96
Δ GDP ($ million)	0.02	0.01	0.06	0.11	0.09
Due to Δ outage ($ million)	0	0	0	0	0
Due to Δ power cost ($ million)	0.02	0.01	0.06	0.11	0.09
Δ GHG emissions (tCO_2e/y)	-882	-1,317	-2,094	-1,529	28
Δ formal jobs	1	1	4	7	5
Δ GDP/capital cost ($/$)	0.02	0.01	0.02	0.07	0.09
Δ GHG emissions/capital cost ($tCO_2e/y/\$$)	-668	-767	-680	-980	29
Δ formal jobs/capital cost (per $)	1	0	1	4	5

[93] U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

Table 24. Climate-development nexus ranking of all combinations using $200 per tCO_2e. All impacts are calculated on an annual basis

Country	Technology	Δ GDP/capital costs ($ million /$ million)	Δ GHG/capital costs (tCO_2e/$ million)	Δ GDP_{net}/capital costs ($ million impact / $ million)[94]
Senegal	CCGT	0.07	-980	0.27
Senegal	Hydropower	0.02	-680	0.16
Senegal	Wind	0.01	-767	0.16
Senegal	Solar PV	0.02	-668	0.15
Senegal	HFO	0.09	29	0.09

Cost of fuel analysis

With the discovery of significant oil and gas reserves on its coast, Senegal is expected to become a significant oil and gas producer in the coming years. Despite this promising development, the country currently relies on fossil fuel imports for approximately 79% of its electricity production. Reliance on fossil fuel imports can create supply shortages, as illustrated by the outages in June 2022 owing to lack of fuel at several Senegal thermal power plants. The fluctuating prices of these imports have also led to an upward trend in electricity tariffs within Senegal. Despite heavy government subsidies, the country boasts some of the highest electricity tariffs in the region, standing at $0.18/kWh compared to the regional average of $0.10/kWh across five other countries in the study.

To illustrate the impact of volatile fossil fuel prices on power generation costs in Senegal, we vary the price of oil as a key parameter in the model while holding all other inputs constant. The ensuing analysis, presented in Table 25, underscores the significant influence of oil costs on overall generation expenses. Notably, the oil price rose sharply in 2022 (a 140% increase compared to 2020), which translated into a 55% surge in generation costs compared to 2020, characterised by a slump in oil prices induced by the COVID-19 pandemic. This heightened volatility in generation costs reinforces the strategic shift away from dependence on fossil fuel imports and towards reliance on a mix of domestic fossil fuels and renewable sources in Senegal's power system.

Table 25. Analysis of impact of price of Brent crude oil on electricity generation costs in Senegal

	2020	2021	2022	2023
Price of Brent crude oil ($/barrel)[95]	42	71	101	82
Generation costs ($/kWh)	0.09	0.12	0.15	0.13
Price of Brent crude oil (year-on-year % change)	-	41%	30%	-23%
Generation costs (year-on-year % change)	-	32%	9%	-9%

[94] This score is calculated by aggregating the economic and climate impact. The GHG impact was converted into an economic impact by using a carbon price of $200/$tCO_2e$.

[95] https://oilprice.com

Sources

Costs and generation

- Overall and plant-level data on variable and fixed costs, IPP tariffs, energy purchases and generated power, was obtained from Senelec's 2022 annual report.

Availability

- Available supply of thermal plants was determined based on annual averages provided by Senelec's Annual Report 2022.
- Available supply of solar power was calculated based on data from the Global Solar Atlas.
- Available supply of wind power was calculated based on data from the NASA POWER project.
- Hydrological data to determine availability of hydropower plants was taken from the African Hydropower Atlas, which also provides estimates for wet, dry and normal years.
- GHG intensities were determined by combining fuel inputs and data on emission factors per technology type from the Greenhouse Gas Protocol's cross-sector tools.

Demand

- Seasonal variations in demand were determined using peak demand data from Senelec's annual reports.
- The load curve of Senegal was established based on a load curve profile of Côte d'Ivoire sourced from IRENA (2018) *IRENA Planning and Prospects for Renewable Power: West Africa*. The load curve was scaled up based on average peak demand estimates per month.

Macroeconomic data

- Labour data was sourced from the ILOSTAT database and from WIEGO (2022) *Informal Workers in Senegal: A Statistical Profile* for the share of the informal economy as a percentage of total GDP.
- GDP data was sourced from the World Bank national accounts dataset.

Annex 5. South Africa

South Africa – executive summary

Context: South Africa's power sector grapples with prolonged outages stemming from an inadequate power supply. The country relies heavily on an outdated fleet of coal plants (73%), posing a significant challenge for climate concerns and contributing to the persisting power deficit. Other energy sources include OCGT (6%), hydropower (6%), renewables (5%) and nuclear energy (3%), highlighting a need for diversification to address the current energy predicament.

Investment with highest economic impact (per unit of capital invested): OCGT.

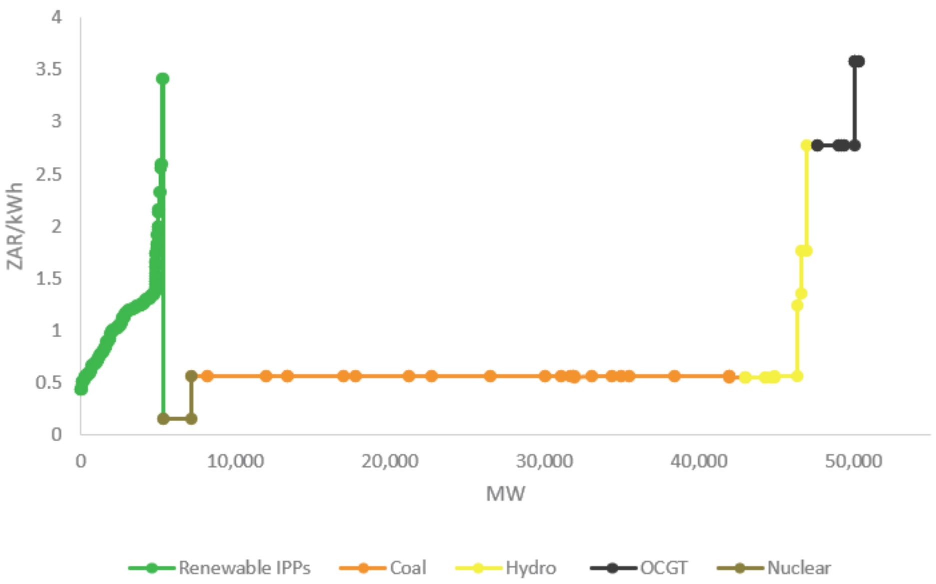
Investment with highest climate impact (per unit of capital invested): Solar PV with battery.

Takeaways:

- In South Africa, because outages are so prevalent throughout the day, the cheapest technologies have the largest economic impact. OCGT becomes the most attractive investment in terms of GDP effect, and solar PV with storage, wind and OCGT are also more attractive than expensive coal.
- In terms of GHG emissions, solar PV with battery, solar PV and wind emerge as the most cost-efficient technologies.

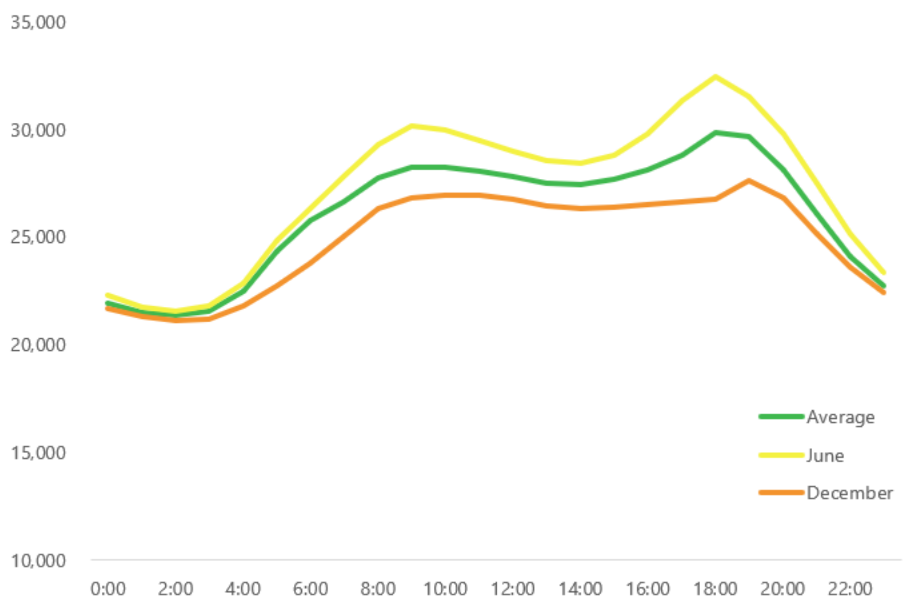
Power model

Figure 36. Merit order of South Africa[96]



The merit order of South Africa deploys feed-in renewables first and then nuclear and coal as base load power. Hydropower and OCGT are used as peaker plants, of which the latter is putting an upward cost pressure on the power system because of high fuel costs.

Figure 37. Typical daily load profile in South Africa (average, June and December)



[96] ZAR (see y axis): South African Rand.

Figure 38. Reserve margin for South Africa

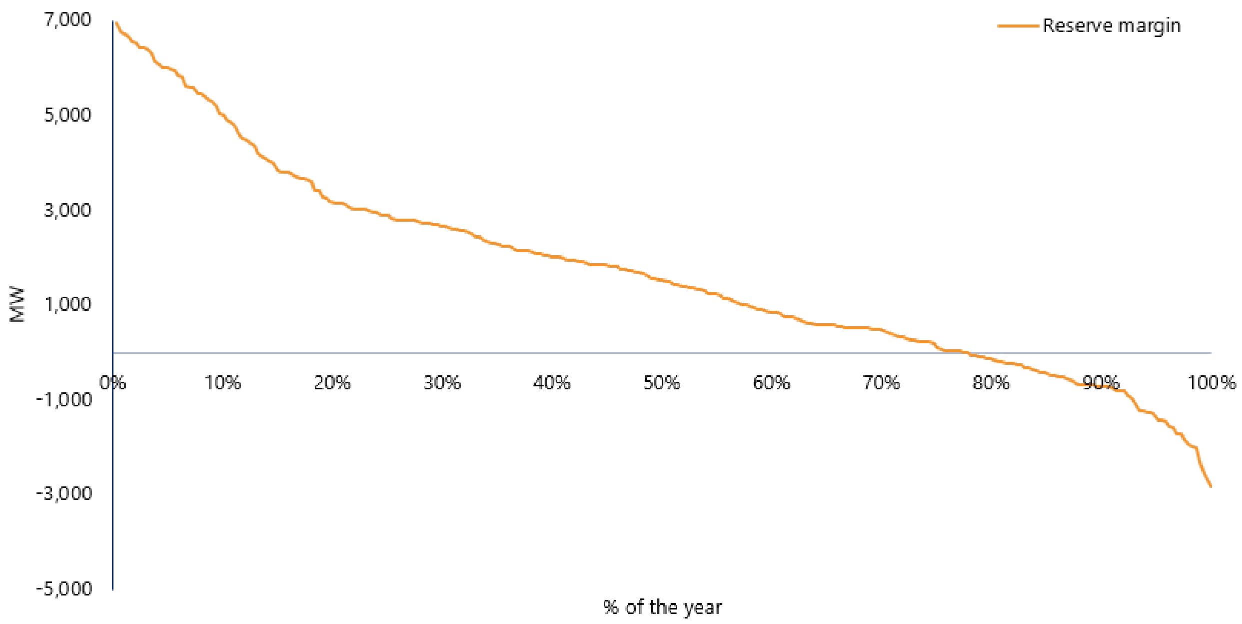


Figure 38 shows the reserve margin of South Africa ranked in descending order of magnitude, and therefore gives an indication of how well the power supply can keep up with demand. The reserve margin is negative for more than 20% of the year, which explains the high incidence of load shedding in the country.

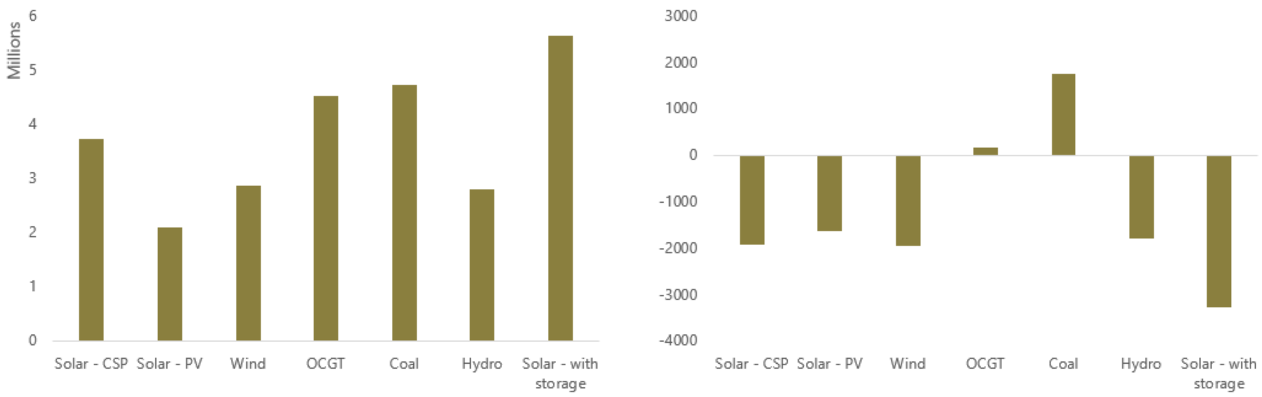
Results

Table 26. Key characteristics of the power system in the baseline model and actual data

Metric	Power model	Actual data
Power capacity [MW]	50,624	50,624
Power production [TWh]	226.6	227.2
Generation cost of power [ZAR/MWh]	828.1	883.7
Number of outages [MWh]	1,716,000	1,775,000
GHG intensity [tCO_2e/MWh]	0.81	0.87

To validate the power model, it was programmed under conditions that reflected the 2021 financial year, which is the latest year for which we have all data available. We looked for four key statistics to confirm that our model matched reality – total production of energy, generation cost, outages, and GHG emissions per tCO_2e.

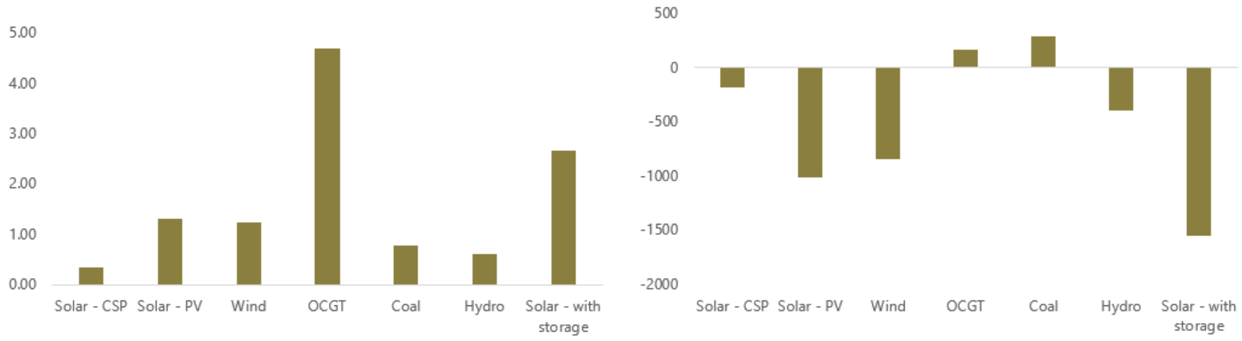
Figure 39. Annual change in GDP (left) and GHG emissions (tCO_2e/y, right) with additional 1 MW of capacity



Main takeaways:

- Per 1 MW increase, solar with storage emerges as the most attractive investment in terms of both its economic impact and climate impact, because it provides a stable, reliable source of energy and can therefore consistently limit outages, and it has no GHG emissions.
- After this, thermal investments (OCGT and coal) have the highest impact on GDP, because they can consistently limit outages throughout the day, owing to their high availability factors. However, they both lead to even more GHG emissions in South Africa, one of the most GHG intense power systems in the world.
- GHG reductions of solar, wind and hydropower are proportional to their capacity factors.

Figure 40. Annual change in GDP (left) and GHG emissions (right) per unit of capital invested



Main takeaways:

- When considering capital costs, solar with storage ranks second in terms of GDP impact and first in terms of GHG reductions, which makes it a considerably more attractive investment than renewables such as solar PV, wind and hydropower.
- Per dollar invested, OCGT becomes the most attractive investment in terms of GDP effect, owing to its low capital costs compared to coal. Investment in coal is less attractive, considering the lower impact on GDP and significant GHG emissions.

Table 27. Overview of socioeconomic impact results per technology for South Africa

1 MW capacity	CSP	Solar PV	Solar + storage	Wind	OCGT	Coal	Hydro
Capital cost ($ million)[97]	10.5	1.6	2.1	2.3	1.0	6.0	4.5
Δ GDP ($ million)	3.7	2.1	5.6	2.9	4.5	4.7	2.8
Due to Δ outage ($ million)	3.9	1.6	5.8	2.3	5.6	4.7	2.4
Due to Δ power cost ($ million)	-0.1	0.5	-0.1	0.5	-1.1	0	0.5
Δ GHG emissions (tCO_2e/y)	-1,918	-1,615	-3,277	-1,935	160	1,768	-1,788
Δ formal jobs	130	73	196	58	157	165	98
Δ GDP/capital cost ($/$)	0.36	1.32	2.66	1.25	4.71	0.79	0.62
Δ GHG emissions/capital cost ($tCO_2e/y/\$$ million)	-182	-1,009	-1,546	-845	167	297	-397
Δ formal jobs/capital cost (per $)	12	46	93	44	164	28	22

[97] U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear & Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

Table 28. Climate-development nexus ranking of all combinations using $200 per tCO2e. All impacts are calculated on an annual basis

Country	Technology	Δ GDP/capital costs ($ million /$ million)	Δ GHG/capital costs (tCO_2e/$ million)	Δ GDP_{net}/capital costs ($ million impact / $ million)[98]
South Africa	OCGT	4.71	167	4.69
South Africa	Solar with storage (EIA)	2.66	-1,546	2.97
South Africa	Solar PV	1.32	-1,009	1.52
South Africa	Wind	1.25	-845	1.42
South Africa	Solar with storage (Kenhardt)	0.88	-511	0.98
South Africa	Coal	0.79	297	0.73
South Africa	Hydropower	0.62	-397	0.70
South Africa	CSP	0.39	-182	0.39

Projected impact of Kenhardt

The Kenhardt power plant is an under-construction solar power plant with battery storage in the Northern Cape of South Africa. It is constructed and majority-owned by Scatec, with BII providing debt to Scatec, and equity through a mezzanine financing structure for H1 Holdings.

The solar PV installation has a 540 MW_p capacity, but in this analysis we use an estimated 435 MW_{AC} capacity.[99] The battery has a 225 MW power capacity and a guaranteed 1,140 MWh energy storage capacity with a 20-year lifetime. The connection to the grid is 150 MW.

Running the model at 2023 conditions, the plant is expected to have a strong impact on reducing outages, is neutral in terms of the cost of power, and greatly reduces GHG emissions.

The plant's projected large impact on GDP and on reducing emissions is somewhat moderated by its high capital cost. Although a photovoltaic-only plant has a smaller impact on GDP and on reducing GHG emissions per MW generated, it has more than double the impact on GDP and on reducing emissions when adjusted for capital cost, because a solar photovoltaic plant with battery storage is significantly more expensive than a photovoltaic-only plant.

[98] This score is calculated by aggregating the economic and climate impact. The GHG impact was converted into an economic impact by using a carbon price of $200/$tCO_2e$.

[99] MW_{AC} = Megawatt(s) (alternating current) is typically some 73%–85% of the (direct current) capacity rating, which is 540 MW_p (the lower estimate is according to the National Renewable Energy Laboratory, which is used as the derate factor by, for example, EMA Singapore; Wikipedia states a range of 80%–85%). This range implies a range of 416-459 MW_{AC} based on 540 MWp.

Table 29. Overview of socioeconomic impact results for Kenhardt

435 MW capacity	Kenhardt
Capital cost ($ million)100	962
Δ outages (%)	-15.9%
Δ power cost (%)	+0.0%
Δ GHG emissions (%)	-0.27%
Δ GHG emissions (tCO2e/y)	-500,003
Δ GDP ($ million)	827
Δ formal jobs	28,786
Δ GDP/capital cost ($/$)	0.88
Δ GHG emissions/capital cost (tCO2e/y/$)	-511
Δ formal jobs/capital cost (per $)	30

Sources

Plant-level data

- **Eskom plants:** to obtain data on contracted and available capacity for Eskom's power plants, we used information from Eskom (2021) *Integrated Report*.[101]
- **Renewable IPPs:** data regarding contracted and available capacity, as well as commission dates for renewable IPPs, was extracted from the Independent Power Producer Procurement Programme website.
- **Non-renewable IPPs:** capacity and commission dates data for non-renewable IPPs was compiled from a variety of sources, including company websites and the Global Energy Monitor.

Costs

- **Renewables:** data on renewable energy tariffs was retrieved from Green Cape (2022). Because there is no plant-level data available on tariffs, we have randomly distributed tariffs from upper bound to lower bound for each of the technologies.
- **Solar with battery storage:** data on the Kenhardt plant was obtained from the website of South Africa's Risk Mitigation IPP Procurement Programme (RMIPPPP).
- **Coal, nuclear and OCGT:** data on fuel costs was obtained from Eskom (2021) *Integrated Report*. In the absence of recent data on O&M costs for South Africa, data from the EIA (2022) was used to derive fixed and variable O&M costs for coal and OCGT plants.

[100] U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

[101] https://www.eskom.co.za/wp-content/uploads/2021/08/2021IntegratedReport.pdf

- **Hydropower:** for Eskom's hydroelectric plants, the model relied on data from Van Dongen and Bekker (2020)[102] to estimate variable O&M costs per plant. Fixed O&M costs were taken from the EIA report (2022). For small hydroelectric IPPs, data on renewable tariffs was used from Green Cape (2022). In the absence of plant-level tariff data, we applied a random distribution of tariffs within the upper and lower bounds for each technology.
- **Generation/transmission costs:** data on transmission and generation costs was extracted from Eskom's cost-to-serve (CTS) study report.[103]

Availability

- **Renewables:** hourly data on power generation in 2021 was provided by Eskom. The model aggregated this data by technology type and calculated average availability factors for each renewable technology. Estimates were generated for each hour of an average day per month.
- **OCGT, nuclear and hydroelectric:** monthly data on energy availability factors per plant from Eskom was used. We assumed that the energy supply of these technologies remained constant throughout the day.
- **Non-renewable IPPs:** no data was available for the energy availability factors of non-renewable IPPs. We therefore adopted the average Energy Availability Factor (EAF) of the respective technology for all Eskom's plants.
- **GHG intensity:** we determined GHG intensities per plant using data from the Eskom Carbon Footprint Study of 2019, which provided GHG emissions data per plant. This information was combined with data on the energy availability factors per plant, also supplied by Eskom.

Demand

To model power demand, hourly data on total energy demand by Eskom was used and was subsequently converted into estimates for each hour of an average day per month.

Macroeconomic data

- Labour data was sourced from the Quarterly Labour Force Survey of the Department of Statistics South Africa (Q1 2021).
- GDP data was sourced from the World Bank national accounts dataset.

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[102] U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

[102] van Dongen, C. and Bekker, B. (2020) Potential for New Pumped Storage Schemes in South Africa. https://grid.sun.ac.za/wp-content/uploads/2020/10/Van-Dongen-and-Bekker-2020-Potential-for-New-Pumped-Storage-Schemes-in-South-Africa-Energycon.pdf

[103] Eskom (2022) Standard tariffs: Cost-to-serve (CTS) study report: 2021/22 Financial year. https://www.eskom.co.za/distribution/wp-content/uploads/2022/11/Attachment-2-Report-2021-22-Tariffs-allowed-cost-to-serve-study-CTS_NERSA-submission-v20220814-y.pdf

Annex 6. Zambia

Zambia – executive summary

Context: Zambia relies primarily on hydropower power (88% of total production), with the remainder of power generation in 2021 coming from thermal (12%) and a minute amount of solar power (>1%). Thermal energy is part of the base load. Zambia is highly hydro-dependent, making it vulnerable to shortages in ongoing drought conditions.

Investment with highest economic impact (per unit of capital invested): HFO.

Investment with highest climate impact (per unit of capital invested): Geothermal.

Takeaways:

- Any additional investment in power will likely have a minimal or negative impact on GDP, because it will cause a rise in the cost of power. Higher costs are inevitable because current costs are not reflective of market prices, owing to artificially low government-subsidised tariffs on hydropower.
- HFO creates the greatest economic impact, owing to its ability to reduce the greatest amount of outages as part of the base load at the lowest cost. This benefit, however, is negated by its substantial GHG emissions. CCGT would offer a similar impact on power outages and GDP while still reducing GHG emissions by displacing the use of HFO during peak periods.
- When considering GHG emissions only, geothermal power emerges as the most attractive renewable energy investment, and it also has a substantial GDP impact. There is significant potential for geothermal energy, particularly in the Rift Valley region, and for wind power along its borders with Tanzania and Mozambique.

Power model

Figure 41. Merit order of Zambia[104]

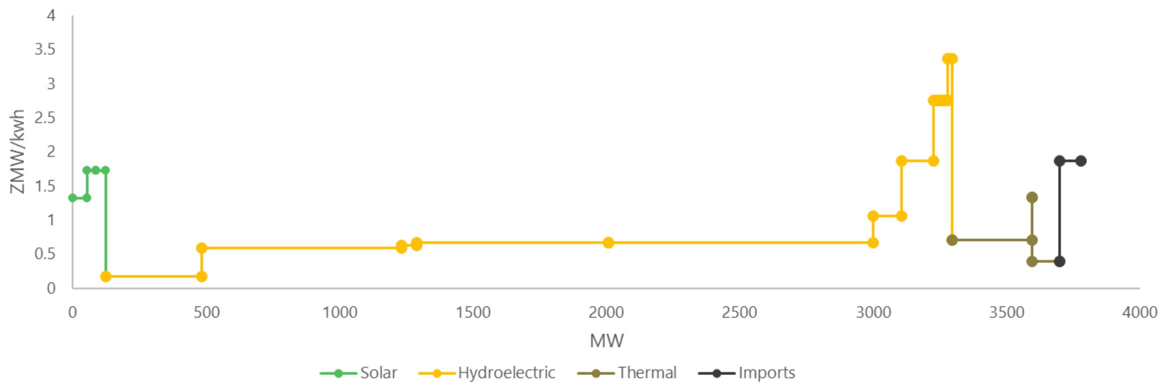
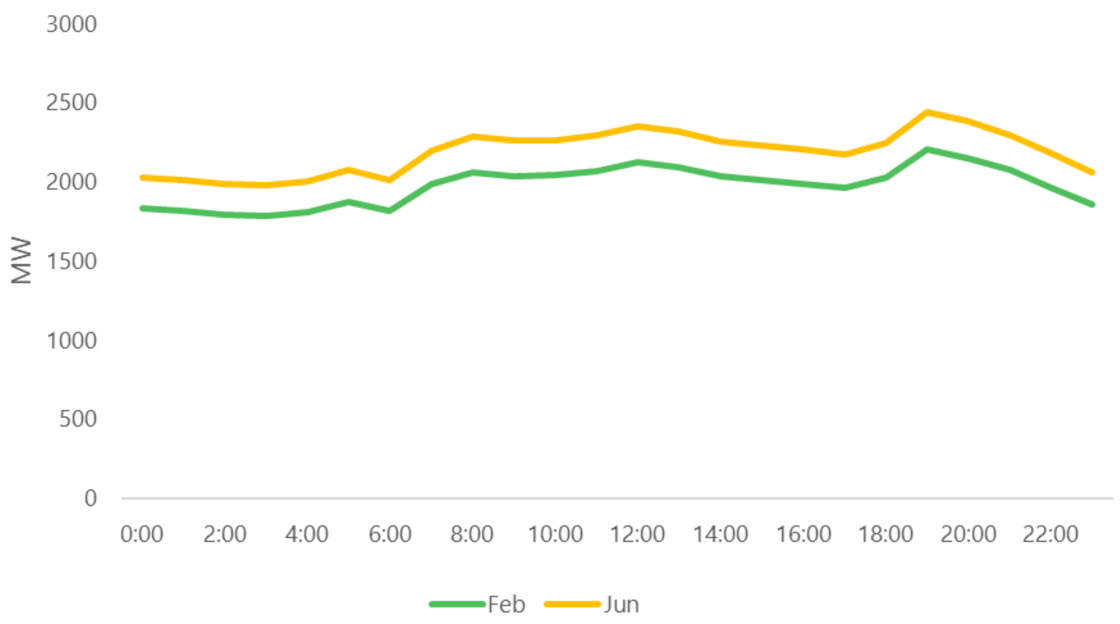


Figure 42. Load curve of Zambia in February (low demand) and June (high demand)



[104] ZMW (see y axis): Zambian Kwacha.

Figure 43. Reserve margin for Zambia

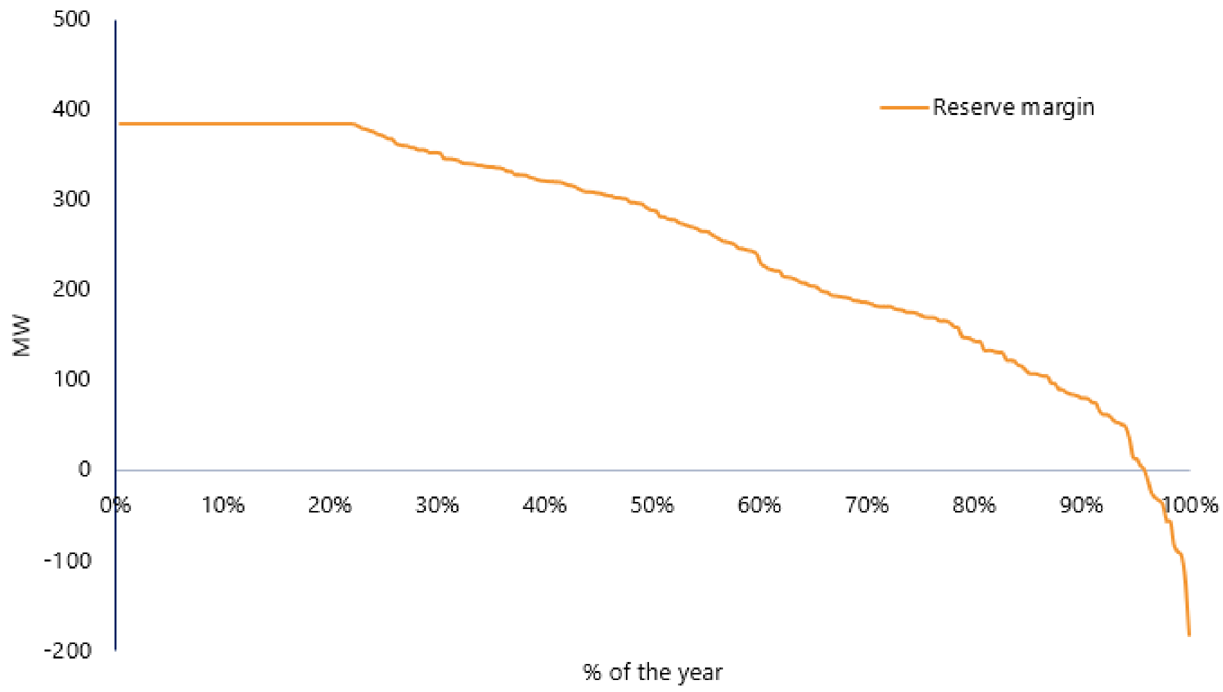


Figure 43 demonstrates the reserve margin for Zambia. The reserve margin is positive for most of the year, which shows the increasing capacity of Zambia's power system and explains the relatively low incidence of outages.

Table 30. Key characteristics of the Zambian power system in the baseline model and actual data

Metric	Power model	Actual data
Power capacity (MW)	3,780	3,357[105]
Power production (TWh)	18.4	17.6[106]
Generation cost of power (ZMW/MWh)	631.0	590.2[107]
Outages as a % of time	4.1	4.0[107]
Outages (hours)	363	350
GHG intensity (tCO_2e/MWh)	0.08	0.08[108]

To validate the power model, it was programmed under conditions that reflected the 2021 financial year, which is the latest year for which we have all the data available. We looked for

[105] Zambia Ministry of Energy (2024) 'Energy Sector'. https://www.moe.gov.zm/?page_id=2198

[106] Zambia Energy Regulation Board (2023) Statistical Bulletin January to December 2022. https://www.erb.org.zm/wp-content/uploads/statBullet2022.pdf

[107] ZESCO (2022) Tariff Application to Energy Regulation Board. https://www.erb.org.zm/wp-content/uploads/files/Tariffs/ZescoApplication2022/ZESCO-TARIFF-APPLICATION-2022.pdf

[108] Based on 2021 emissions and electricity generation data in Zambia from IEA (n.d.) 'Zambia'. https://www.iea.org/countries/zambia/electricity

four key statistics to confirm that our model matched reality – total production of energy, generation cost, outages, and GHG emissions per tCO_2e.

Figure 44. Annual change in GDP (left) and GHG emissions (tCO_2e/y, right) with additional 1 MW of capacity

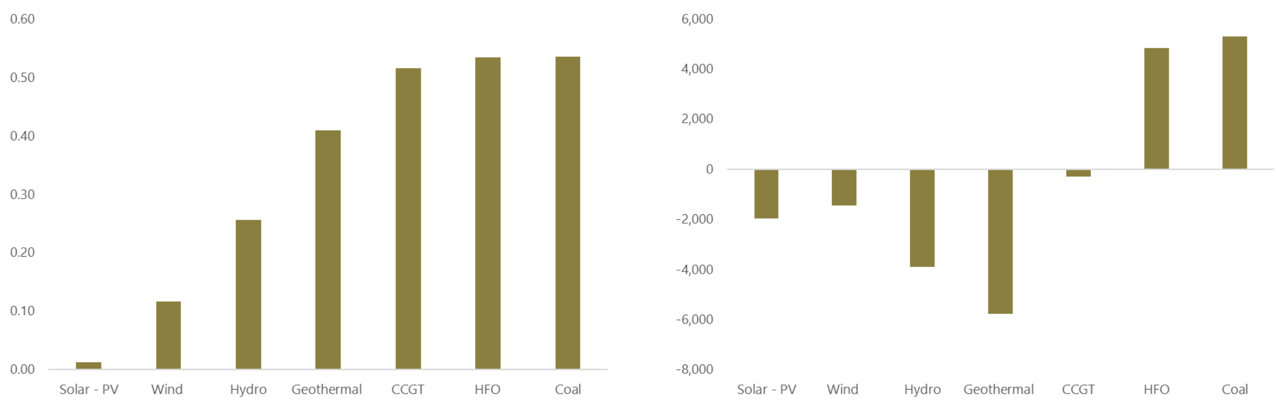
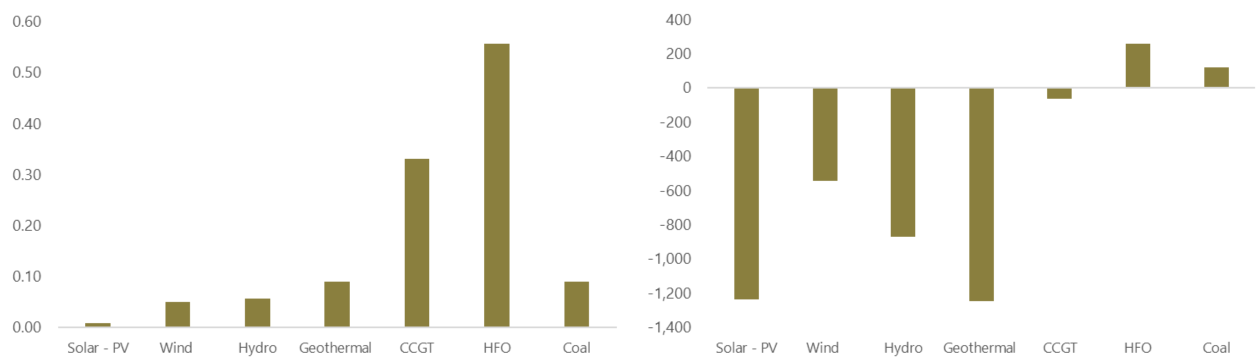


Figure 45. Annual change in GDP (left) and GHG emissions (right) per unit of capital invested



Main takeaways:

- Adding any additional energy generation to Zambia's grid raises prices. This is because of the low price of government-subsidised hydropower.
- Solar power has a small GDP impact, because outages occur at night, and the cost effect is negative, owing to crowding out by government-subsidised hydropower.
- Both coal and HFO reduce outages in Zambia, leading to a substantial effect on the GDP. HFO has a greater impact on the GDP because its capital costs are significantly lower than coal. The higher impact of coal and HFO on GHG emissions is a major trade-off against this greater GDP effect.
- Geothermal has a large GDP and GHG impact because of its low cost and its consistently high capacity factor.
- CCGT has a positive GDP and GHG reduction impact because of its high and consistent levels of availability, combined with its potential to displace use of HFO and coal, both of which have substantially high emissions factors.

Table 31. Overview of socioeconomic impact results for Zambia

1 MW capacity	Solar	Wind	Hydro	Geo-thermal	CCGT	HFO	Coal
Capital cost ($ million)[109]	1.32	1.78	3.53	3.08	1.23	2.08	4.10
Δ GDP ($ million)	0.01	0.12	0.26	0.41	0.52	0.53	0.54
Due to Δ outage ($ million)	0.03	0.11	0.29	0.46	0.54	0.54	0.54
Due to Δ power cost ($ million)	-0.02	0.00	-0.04	-0.05	-0.03	-0.01	-0.01
Δ GHG emissions (tCO_2e/y)	-1,969	-1,240	-3,915	-5,602	-99	+247	+704
Δ formal jobs	1	12	25	41	51	53	53
Δ GDP/capital cost ($/$)	0.01	0.05	0.06	0.09	0.33	0.56	0.09
Δ GHG emissions/capital cost (tCO_2e/y/$ million)	-1,231	-628	-865	-1,285	-194	5,037	888
Δ formal jobs/capital cost (per $ million)	1	7	13	20	8	15	33

Table 32. Climate-development nexus ranking of all combinations using $200 per tCO_2e. All impacts are calculated on an annual basis

Country	Technology	Δ GDP/capital costs ($ million /$ million)	Δ GHG/capital costs (tCO_2e/$ million)	Δ GDP_{net}/capital costs ($ million impact / $ million)[110]
Zambia	CCGT	0.33	-194	0.37
Zambia	Geothermal	0.09	-1,285	0.35
Zambia	Solar PV	0.01	-1,231	0.25
Zambia	Hydropower	0.06	-865	0.23
Zambia	Wind	0.05	-628	0.18
Zambia	Coal	0.09	888	-0.09
Zambia	HFO	0.56	5,037	-0.45

[109] U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis (2022) 'Annual Energy Outlook 2022'.

[110] This score is calculated by aggregating the economic and climate impact. The GHG impact was converted into an economic impact by using a carbon price of $200/$tCO_2e$.

Sources

Costs and generation

- Information on individual plants was obtained from ERB (2022) *2021 Energy Sector Report*.
- PPA and IPP capacity charges were obtained from Energy Market and Regulatory Consultants Limited (2021) *Zambia: Electricity Cost of Service and Tariff Study: Task 5 Report – Determination of Economic Cost of Supply, and Structure and Level of Tariffs*.

Availability

- Available supply of hydropower plants was determined based on annual generation data from 2021 and 2022 from ERB's 2022 Statistical Bulletin in conjunction with RES4Africa Foundation and Enel Foundation's Report on Integration of Variable Renewable Energy Sources in the National Electric System of Zambia.
- Available supply of thermal IPPs was compiled from a variety of sources, including company websites and the Global Energy Monitor.
- Available supply of solar power was calculated based on data from the Global Solar Atlas.
- Available supply of wind power was calculated based on data from the NASA POWER project.
- GHG intensities were derived based on IEA data on emissions per electricity generation source in Zambia.

Demand

- Seasonal variations in demand were determined using demand data from monthly consumption of electricity data from ERB's 2021 Statistical Bulletin.
- The load curve of Zambia was based on an average of several daily load curves distributions published on ERB's System Operator platform.
- Information on transmission losses was derived from ERB (2022) *2021 Energy Sector Report*.

Macroeconomic data

- Labour data was sourced from the ILO.
- GDP data was sourced from the World Bank national accounts dataset.

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