SOUTH AFRICA'S ENERGY SECTOR INVESTMENT REQUIREMENTS **TO ACHIEVE ENERGY SECURITY AND NET ZERO GOALS BY 2050**

2025

DBSA
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SA-TIED
Southern Africa – Towards Inclusive Economic Development

PRESIDENTIAL CLIMATE COMMISSION

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Foreword

The path to South Africa's energy future demands both clarity of vision and courage of action. This comprehensive study, South Africa's Energy Sector Investment Requirements to Achieve Energy Security and Net Zero by 2050, represents a critical milestone in our nation's journey toward sustainable development and energy independence.

South Africa stands at a pivotal moment. After years of debilitating load shedding that have constrained our economy and tested the resilience of our citizens, we are finally witnessing signs of recovery in our energy sector. Yet the challenges ahead remain formidable. Meeting our Nationally Determined Contributions (NDC) under the Paris Agreement, achieving the ambitious targets set forth in our National Development Plan Vision 2030, and ensuring universal energy access for all South Africans, in line with the United Nations’ Sustainable Development Goals (SDGs), will require unprecedented levels of investment, coordination, and political will. These objectives are supported by a comprehensive framework of national strategies and policies, including the Just Energy Transition Investment Plan, the Integrated Resource Plan 2019 and Draft Integrated Resource Plan 2023, the Transmission Development Plan 2024, the National Infrastructure Plan 2050, our Nationally Determined Contributions towards a net-zero future, the Low Emission Development Strategy, and the Climate Change Act.

This study, undertaken through a strategic partnership between the Development Bank of Southern Africa, Presidential Climate Commission, National Planning Commission, and National Treasury's SA-TIED programme, integrates and advances the substantial foundation laid by our nation's key strategic documents and the 2023 World Bank Group "Going Beyond the Infrastructure Funding Gap: A South African Perspective" study. Furthermore, this analysis has been developed while remaining cognisant of the forthcoming Integrated Resource Plan 2025, with a view to contributing to the dialogue of our evolving policy landscape.

By applying rigorous modelling techniques and conducting extensive stakeholder consultations, the research team has developed three distinct pathways, which have been translated into three technical modelling scenarios that illuminate the trade-offs and opportunities inherent in our energy transition. The findings are both sobering and encouraging. While the investment requirements are substantial, ranging from R3.6 trillion to R4.2 trillion through 2050, the study demonstrates that the pathway most aligned with our climate commitments, the Green Industrialization pathway (Scenario A), paradoxically requires the lowest total system investment. This counter-intuitive finding underscores a fundamental truth: investing in our sustainable future represents not merely an environmental imperative but also an economic opportunity.

Particularly significant is the study's emphasis on the primacy of renewable energy technologies, supported by battery storage and flexible gas capacity, as the least-cost solution for meeting our energy needs. The analysis reveals that, by 2050, depending on the chosen pathway, between 70% and 85% of our electricity generation capacity could come from renewable sources. This transformation would optimally position South Africa not only to meet its climate commitments but also to become a competitive supplier of clean energy technologies to the rapidly growing African market.

However, achieving these outcomes will require more than technical solutions. The study's findings on the funding gap, particularly the near-term capital requirements under the Green Industrialization pathway, highlight the urgent need for regulatory reform, market development, and innovative financing mechanisms. The fragmentation of our current regulatory framework and the absence of unified legislative priorities for energy infrastructure investment pose significant barriers that must be addressed with urgency. A parallel socio-economic study on the Green Industrialization pathway demonstrates that this approach can deliver both positive GDP growth and environmental benefits nationally, while requiring targeted social protection in regions such as Mpumalanga, which face adjustment challenges. The analysis confirms that delaying this transition would be far more costly than the investment needed to ensure green and just outcomes, with Green Industrialization proving the most viable option compared to a baseline scenario.

As we engage with the findings of this study, we must remember that the choices we make today will determine the quality of life for generations of South Africans to come. The evidence presented here should inform not only our National Dialogue but also concrete policy actions that will unlock the investments needed for our energy transition. The time for deliberation alone has passed; we must now move decisively toward implementation.

We commend this study to policymakers, investors, civil society, and all stakeholders in South Africa's energy future. May it serve as both a roadmap and a catalyst for the transformative action our nation requires.

Signed by:

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Abbreviations

Term	Definition
APS	Announced Pledges Scenario
AQ	Air Quality
BAU	Business-As-Usual
B-BBEE	Broad-Based Black Economic Empowerment
BESS	Battery Energy Storage Systems
BQ	Budget Quote
Capex	Capital Expenditure
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
CES	Constant Elasticity of Substitution
CET	Constant Elasticity of Transformation
CfD	Contracts For Difference
CGE	Computable General Equilibrium
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COD	Commercial Operation Date
CoGTA	Department of Cooperative Governance and Traditional Affairs
CO_2 tax	Carbon Emissions Tax
CoPS	Centre of Policy Studies
CPA	Central Purchasing Agency
CPI	Consumer Price Index
CST	Centre for Sustainability Transitions
DAC	Development Assistance Committee

DEE	Department of Electricity and Energy
DBSA	Development Bank of Southern Africa
DFFE	Department of Forestry, Fisheries and the Environment
DFI	Development Finance Institution
DMRE	Department of Mineral Resources and Energy
DPE	Department of Public Enterprises
DTIC	Department of Trade, Industry and Competition
EAF	Energy Availability Factor
EC	Eastern Cape
EDGAR	Emissions Database for Global Atmospheric Research
EEG	Renewable Energy Sources Act
ENL	Energy Not Delivered
EPC	Engineering, Procurement, and Construction
ERA	Electricity Regulation Act
ESG	Environmental, Social, And Governance
ESIPPPP	Energy Storage Independent Power Producer Procurement Programme
ESO	Electricity System Operator
ESRG	Energy Systems Research Group
EV	Electric Vehicle
FGD	Flue Gas Desulphurization
FiT	Feed-In Tariff
FOM	Fixed Operation and Maintenance
FS	Free State
GAU	Grid Access Unit
GCCA	Generation Connection Capacity Assessment
GDP	Gross Domestic Product

GEMPACK	General Equilibrium Modelling Package
GHG	Greenhouse Gas
GI	Green Industrialization
GIS	Geographic Information System
GIPPPP	Gas Independent Power Producer Procurement Programme
Gt	Giga tons
$GtCO_2e$	Giga tons of carbon dioxide equivalent
GW	Gigawatt
GWh	Gigawatt hour
HC	Hydra Central
Hz	Hertz
HVDC	High-Voltage Direct Current
IDC	Industrial Development Corporation of South Africa
IEA	International Energy Agency
IEP	Integrated Energy Plan
IPCC	Intergovernmental Panel on Climate Change
IPG	International Partners Group
IPP	Independent Power Producer
IPPO	Independent Power Producer Office
IRENA	International Renewable Energy Agency
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
IoT	Internet Of Things
JET	Just Energy Transition
JET IP	Just Energy Transition Investment Plan
JETP	Just Energy Transition Partnership

JIBAR	Johannesburg Interbank Average Rate
JSE	Johannesburg Stock Exchange
JTF	Just Transition Framework
kWh	Kilowatt-Hour
KZN	Kwazulu-Natal
LEAP	Low Emissions Analysis Platform
LM	Limpopo
MES	Minimum Emission Standards
MoManI	Model Management Infrastructure
MP	Mpumalanga
Mt	Megatons
$MtCO_2$	Metric Tons of Carbon Dioxide
$MtCO_2e$	Metric Tons of Carbon Dioxide Equivalent
MW	Megawatt
MWh	Megawatt hour
NBI	National Business Initiative
NC	Northern Cape
NCCRP	National Climate Change Response Policy
NDC	Nationally Determined Contributions
NDP	National Development Plan
NECOM	National Energy Crisis Committee
NERSA	National Energy Regulator Of South Africa
NPC	National Planning Commission
NPO	Non-profit Organization
NREL	National Renewable Energy Laboratory
NSP	Network Service Provider

NTCSA	National Transmission Company South Africa SOC Ltd
NW	North West
NZE	Net Zero Emissions by 2050 Scenario
OECD	Organisation For Economic Co-Operation and Development
O&M	Operations And Maintenance
OMM	Oliphants Management Model Programme
ONEE	Office National De l’Electricité Et De l’Eau Potable
OCGT	Open Cycle Gas Turbines
Opex	Operational Expenditure
OSeMOSYS	Open-Source Energy Modelling System
PCC	Presidential Climate Commission
PCCC	Post Combustion Carbon Capture
PFMA	Public Finance Management Act
PHS	Pumped Hydro Storage
PIR	Policy, Institutional, and Regulatory
PPA	Power Purchase Agreements
PTC	Production Tax Credit
PV	Photovoltaic
R&D	Research and Development
REC	Renewable Energy Certificate
REIPPP	Renewable Energy Independent Power Producers Procurement
REIT	Real Estate Investment Trust
RES	Reference Energy System
RFP	Request for Proposal
ROC	Renewables Obligation Certificate
RPS	Renewable Portfolio Standards

SALGA	South African Local Government Association
SAPP	Southern Africa Power Pool
SARS	South African Revenue Service
SAREM	South African Renewable Energy Masterplan
SA-TIED	Southern Africa – Towards Inclusive Economic Development
SDG	Sustainable Development Goal
SMR	Small Modular Reactor
SOE	State-Owned Enterprise
SPP	Strategic Partnership Programme
SSEG	Small-scale embedded generation
STEPS	Stated Policies Scenario
SU	Stellenbosch University
TDP	Transmission Development Plan
TSO	Transmission System Operator
UCT	University of Cape Town
UNFCCC	United Nations Framework Convention on Climate Change
UP	University of Pretoria
UPGEM	University of Pretoria General Equilibrium Model
VOM	Variable Operation and Maintenance
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital
WC	Western Cape
WEF	World Economic Forum
WEO	World Energy Outlook
WHO	World Health Organization

Executive Summary

Purpose and Scope

The Development Bank of Southern Africa, Presidential Climate Commission, National Planning Commission, and National Treasury (via its programme Southern Africa – Towards Inclusive Economic Development (SA-TIED)), share similar commitments towards socio-economic development, energy security and access, the Just Energy Transition (JET), and achieving the climate commitments of South Africa.

To that end, this strategic partnership appointed a project team led by PwC and supported by Osmotic Eskom2030 (and extended to 2040 and 2050) to achieve the energy and carbon targets as specified in the South African Nationally Determined Contributions (NDCs), the National Development Plan (NDP), National Infrastructure Plan (NIP), and the United Nations (UN) Sustainable Development Goals (SDGs), specifically SDG 7 (affordable and clean energy). The objectives of this study pertain to the need to achieve energy security at least cost while meeting South Africa's NDC targets. Furthermore, the team needed to assess the funding gap to achieve the afore-mentioned outcomes.

These objectives were achieved by modelling several energy mix pathways as scenarios, which were developed through a consultative process with the project partners and included evaluating a range of modelling sensitivities. Through power systems and energy[1] modelling (collectively termed technical modelling), these scenarios provide the investment required, i.e., the capital and operational expenditure (Capex and Opex) per annum, to achieve the stated targets.

In addition, the project team conducted a soft market sounding[2] of potential financiers within the energy landscape to obtain insights regarding the estimation of the funding gap and existing regulatory barriers. The team conducted a detailed assessment of the funding gap and completed a Policy, Institutional, and Regulatory (PIR) analysis of the energy financing landscape. This report is supported by a literature review (DBSA, National Treasury, NPC, PCC, 2025b) to inform the analysis, which allows for a results comparison. Additionally, a socio-economic impact modelling study has been completed using the scenario output from this study's technical modelling and will be published in a supplemental report (DBSA, NT, NPC, PCC, 2025c).

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1 For the purposes of this report, 'energy' is defined as electricity, encompassing renewable sources, coal, gas, uranium, and diesel. From an infrastructure perspective, the report deals with electricity generation, storage, transmission, and distribution infrastructure. Upstream infrastructure for the supply of coal, gas, and diesel fuels is incorporated in the unitised cost of these energy sources as they are consumed by the associated electricity generation plants, i.e., the study does not estimate the investment required for upstream infrastructure such as gas pipelines, liquefied natural gas (LNG) terminals, petrochemicals manufacturing, and coal mines.

2 Market sounding is an approach to gauge investors' market interest in funding projects. Due to the lack of project-specific information and the timeline spanning 25 years, the questions in this instance are less detailed and are referred to as a soft market sounding exercise. In addition, relative to traditional research, market soundings where participants may submit responses in writing and detailed information shared beforehand, participants were not required to do that in this case.

This work will contribute to the broader SA-TIED Workstream 5, focusing on the water-energy-food nexus in the context of climate change. The study does not address these nexus issues, but it forms part of the groundwork for the ongoing work on this topic.

At the time of writing, the IRP2019 and Draft IRP2023 were published, with the knowledge of a Draft IRP due later in 2025. The technical modelling approach for this study is broadly similar to that used for previous IRPs. In addition, the demand forecast assumption for this study is the same as the demand forecast used in the Draft IRP2023. This study involved three main scenarios, with each scenario based on a least-cost optimization, but with differing input variables such as carbon budgets, carbon tax, technology costs, fuel costs, and cost of capital. While many of the input variables are similar to those of the Draft IRP2023, the exact combination used in each scenario in this study differs from past IRP scenarios and may differ from those of the Draft IRP2025. The intention of the modelling conducted in this study is to contribute to the body of literature in the electricity sector, and to elicit discussion on the most optimal and practical energy and carbon pathways for South Africa.

Methodology

The World Bank’s Beyond the Gap methodology (see Rozenberg and Fay, 2019) was applied, with two additional steps. The methodology applied can be divided into the following steps:

- **Identify objectives:** The objectives for this study pertain to the need to achieve energy security at least cost while meeting South Africa’s NDC targets. Apart from the NDC targets, these objectives also directly affect South Africa’s achievement of the SDGs, specifically SDG 7, and link to the NDP. The following metrics represent these objectives:
    - **Energy security and affordability objectives:** Achieve 90% electricity access to all areas by 2030, with non-grid options available for the rest (RSA, 2021). As per SDG 7.1, ensure universal access to affordable, reliable, and modern energy services by 2030.
    - **Climate objectives:** Reduce annual carbon emissions to 398–510 MtCO_2e by 2025, and 350–420 MtCO_2e by 2030 in accordance with South Africa’s NDC targets.
        - As per SDG 7.2, increase the share of renewable energy in the global energy mix substantially by 2030. The NDP supports the development and adoption of renewable energy sources as part of a transition to a more sustainable energy system.
        - As per SDG 7.3, double the (global) rate of improvement in energy efficiency by 2030. The NDP aims to improve energy efficiency across sectors to reduce energy consumption and lower greenhouse gas emissions.
        - According to the NDP’s stated goals, procure at least 20 000 MW of renewable electricity by 2030, import electricity from the region, decommission 11 000 MW

of ageing coal-fired power stations, and increase investments in energy efficiency overall (RSA, 2021).

- **Identify the metrics to monitor infrastructure services:** These metrics are used to monitor South Africa's NDC targets, their performance against SDG 7 targets, and their link to the NDP. Specifically, these are:
    - **Electricity access:** The share of South Africans with access to grid power is currently estimated to be 86.5% (United Nations Statistics Division (UNSD), 2023).
    - **The contribution of renewable energy to the country's total energy portfolio:** In 2021, this figure stood at 9.7% (UNSD, 2023).
    - **Energy efficiency:** The latest available data from 2021 showed the ratio between energy supply and economic output was 6.6 megajoules per constant 2017 purchasing power parity gross domestic product (MJ/USD 2017 PPP GDP) (UNSD, 2023).
    - **Energy availability factor (EAF):** For the 2024 calendar year, South Africa's energy availability factor averaged 59.8% (Eskom, 2025).
    - **Affordability of technology options:** This metric is expressed as a per annum cost for Capex and Opex in 2024 real terms, which is comparable across various scenarios.
    - **Annual carbon emissions (CO_2e):** In 2022 (the latest available data), South Africa's estimated emissions were 436 $MtCO_2e$ (Department of Forestry, Fisheries and the Environment, 2024), which exceeds the 350–420 $MtCO_2e$ target.

- **Identify the types of options available:** Three energy scenarios (including sensitivity testing) were developed considering the following considerations:
    - **Pathway and scenario-specific inputs and assumptions**
        - Policy and regulations: 1) carbon emissions from electricity, 2) adherence to air quality standards, 3) Carbon Border Adjustment Mechanism and other export market regulations, and 4) carbon emissions tax;
        - Generation: 1) coal fleet decommissioning schedule, 2) energy availability factor, 3) carbon capture storage viability timeline, and 4) technology learning rates;
        - Fuel prices; and
        - Capital: 1) size of the market and available funding, and 2) cost of capital.
    - **Universal inputs and assumptions**
        - Generation: 1) embedded generation (on-site), 2) Commercial & Industrial Private wheeling Gx, 4) grid expansion rate and generation build rate, and 5) technology options (including load shedding and unserved energy);

  - Demand: 1) universal access to electricity, 2) demand and energy forecasts per sector, 3) fuel switching, and 4) electric vehicles; and
  - Regional electricity trade (via the Southern Africa Power Pool).

- **Identify exogenous factors:** Exogenous factors that might influence the magnitude of funding required towards 2050 were considered as part of the (energy) pathways development process. These included aspects such as: 1) the degree of international collaboration and coordination of climate change action, 2) international and local economic conditions, 3) energy demand patterns, 4) climate events, 5) global energy prices, and 6) technology advances that could influence the cost of capital and appetite for investment into South Africa's electricity infrastructure. Along with determining the available options, these exogenous factors influenced the determination of the South African carbon budget range up to 2050.
- **Estimate costs of achieving objectives:** This step was completed in two broad ways. Firstly, extensive technical modelling was conducted, including energy (electricity generation) and power systems (grid stability) modelling. This was informed by technical consultation sessions to obtain new estimations for the capacity build programme, energy mix, and total Capex. The results were compared to the corresponding ranges identified in the parallel literature review study. In addition, a supplementary Computable General Equilibrium (CGE) modelling report will be produced to provide insight into the socio-economic impact stemming from the pathways and scenarios generated in this report.
- **Estimate the funding gap:** A soft market sounding exercise with market participants (equity and debt funders of energy infrastructure projects) was conducted to determine the magnitude of available Capex funding within the energy infrastructure sector and to determine the potential funding gap (i.e., capital available vs capital required) to reach the investment required over a forecast period to 2050. To address the remaining funding gap, a range of funding options and their respective mobilization requirements (i.e., financial, policy, institutional, regulatory, or technical) were considered. Based on the outcomes from the soft market sounding exercise, current public and private spending on energy infrastructure, and the Capex financing requirement ranges obtained from the technical modelling performed, the funding gap was estimated. These findings were compared to the ranges that were identified in the parallel literature review study.
- **Regulatory analysis:** A detailed assessment of the policy and regulatory frameworks that govern the flow of public and private investments in energy infrastructure was conducted. Required PIR changes to enable an increased level of investment in climate-resilient energy infrastructure were identified, with recommendations made based on input from soft market sounding participants, international examples, and leading practice within the context of the current South African energy landscape.

Pathways and Scenarios

The project team, with inputs and oversight from the Project Steering Committee, provided a range of local and international pathways that provide the overarching conditions and limitations for the associated model scenarios. While informed by a wide range of data and information, these pathways are based on South Africa's JET-IP (The Presidency, 2022), the carbon budget between 2010 to 2050 which was originally defined in the National Climate Change Response White Paper (RSA: NCCRP, 2014), and South Africa's Intended Nationally Determined Contribution (DFFE: SA-LEDS, 2020), which was presented to the United Nations Framework Convention on Climate Change (UNFCCC) (2020).

The international development pathways are:

- **Pathway 1:** Global alignment to keep global warming to below 1.5 degrees Celsius in relation to pre-industrial levels as per the Paris Agreement,
- **Pathway 2:** A fragmented world, where only certain countries achieve their NDC targets and warming is limited to below 3 degrees Celsius, and
- **Pathway 3:** Business-as-usual, where climate commitments generally stall and fail, with global warming exceeding the 3 degrees Celsius threshold.

The local development pathways are:

- The **Green Industrialization** pathway assumes that the country is fully aligned and has an environmentally conscious and low-emissions development strategy to curtail global warming, which drives a carbon emissions limit of 2 Gt by 2050 for the electricity sector and mandates AQ compliance by 2030. With this pathway, a large market exists for green industrialization finance, and the capital cost is low and accessible for renewable energy technologies, whereas the capital cost for fossil fuel technologies attracts a premium. In addition, the new technology learning rates are optimistic and project reduced costs; the competition for fossil fuels is low, resulting in lower coal and gas prices; and an improved EAF for the existing coal fleet.
- The **Market Forces** pathway assumes that the country is generally aligned to its NDC targets, but that the cost of capital and other global and or local economic factors influence decisions on the country's energy mix that could limit South Africa's ability to maintain strict adherence to AQ standards and carbon policies. This pathway assumes a carbon emissions limit of 3 Gt by 2050 for the electricity sector, and AQ compliance is only mandated by 2035. New technology learning rates, coal and gas prices, and EAF of the existing coal fleet are all assumed to be middle-of-the-road scenarios.
- The **Business-as-usual** aligned investments pathway reflects an abandonment of South Africa's NDC commitments due to a breakdown in global alignment or acute economic cost

challenges. The result is a focus on electricity production through the least cost and the availability of supply.

The three scenarios modelled for this study represent different intersections of the local and global pathways, and are based on various assumptions relating to the conditions defined for these pathways:

- **Scenario A** represents the intersection of the global alignment (international) pathway and green industrialization (local) pathway.
- **Scenario B** represents the intersection of the fragmented world (international) pathway and market forces (local) pathway, and
- **Scenario C** represents the intersection of the business-as-usual (international) pathway and the business-as-usual (local) pathway.

The research was conducted over a two-year period spanning from June 2023 through June 2025, during which all data collection, analysis, and interpretation were completed.

Results and Findings

Operating Capacity

The infrastructure technical modelling identified the energy mix with the lowest investment requirement to meet national electricity demand, based on various input assumptions and model constraints for each scenario. The operational capacity required for each generation and storage technology by 2030 and 2050, for each scenario, is shown in Table 1 and Figure 1.

Scenario A results in the largest and most accelerated roll-out of solar PV and wind, supported by battery energy storage systems (BESS) and gas (at a low-capacity factor). It also results in the fastest decommissioning of the coal fleet. Scenarios B and C result in progressively less solar PV, wind, and BESS capacity, with more coal remaining online for longer. Gas capacity also features in scenarios B and C, to a larger extent than in Scenario A, at a relatively low-capacity factor, indicative of peaking operation.

Given the urgent need to address energy shortages over the short- to medium-term (2025–2035), no new coal or nuclear capacity is envisaged during this period. Furthermore, the modelling reveals that across all three scenarios, the system can meet reliability and emissions constraints through a mix of renewables, storage, and flexible gas capacity without requiring new coal or nuclear investments through to 2050.

Table 1: Operating Capacity per Technology in 2025, 2030, and 2050 per Scenario (GW units)

Year	Technology	Scenario A (Green Industrialization)	Scenario B (Market Forces)	Scenario C (Business-as-usual)
2025	Solar	13	13	13
	Wind	4	4	4
	BESS	-	-	-
	Gas	-	-	-
	Coal	37	37	37
	Hydro	4	4	4
	Nuclear	2	2	2
2030	Solar	31	21	23
	Wind	18	11	10
	BESS	11	2	2
	Gas	9	7	5
	Coal	14	34	34
	Hydro	4	4	2
	Nuclear	2	2	2
2050	Solar	99	64	52
	Wind	48	33	32
	BESS	53	33	25
	Gas	23	26	29
	Coal	10 (CCS)	10 (CCS)	11
	Hydro	5	5	5
	Nuclear	2	2	2

Note: Operating capacity refers to total system capacity available in each year, calculated as existing capacity minus decommissioned capacity plus any new capacity added. This includes both legacy and new-build plant that remains online in the model year.

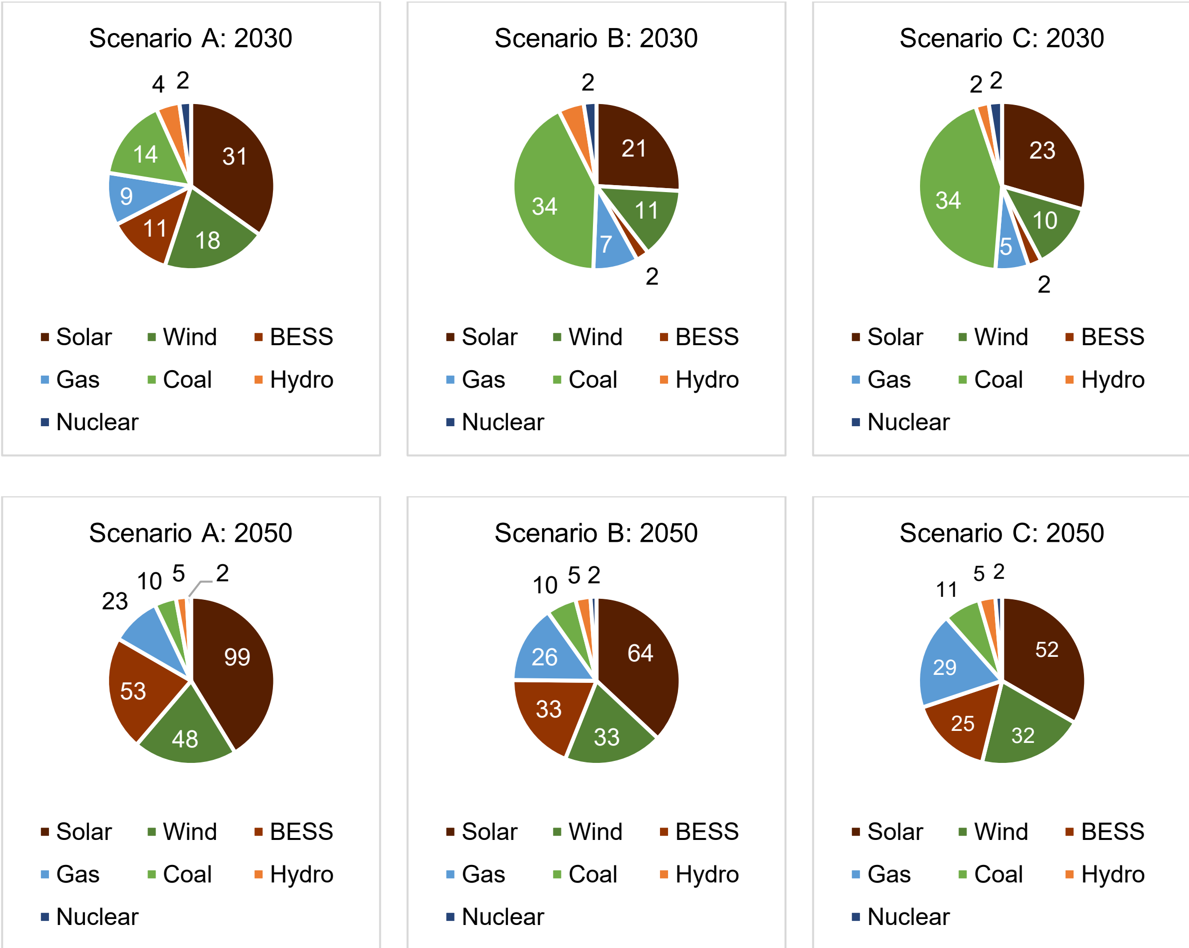

Figure 1: Operating Capacity per Technology in 2030 and 2050 per Scenario (GW units)

Grid Expansion

In all scenarios, the highest power flow is from Free State to Gauteng and Northern Cape to Gauteng via North West, followed by the flow from Hydra Central to Free State. In scenarios A and B, significant renewable energy capacity is built, with a larger portion located in the Northern Cape and Hydra Central due to the favourable VRE resource. The transmission corridor is then required to transport this VRE power to the load centre in Gauteng; hence, the biggest transmission corridors are the Northern Cape to Gauteng via the North West and Hydra Central to Gauteng via the Free State. In addition, power from the Eastern Cape is transported to Gauteng via the Free State – Gauteng / Mpumalanga corridor, and similarly, power from Limpopo is transported to Gauteng via the North West – Gauteng corridor.

The required transmission backbones, collection lines, and substations, as well as distribution collector networks (for VRE and BESS capacity), were quantified based on the geographic location of new capacity and the required corridor flows. The cost of distribution collector networks is large compared to the total grid expansion investment, representing 53%, 47% and 43% of total grid expansion investment for scenarios A, B, and C, respectively.

CO_2 Emissions

CO_2 emissions constraints were applied to scenarios A and B. Scenario A's constraint was based on meeting or exceeding the current NDC targets, while Scenario B's constraint was based on partially exceeding the current NDC targets. Scenario C was unconstrained from a CO_2 emissions perspective. None of the scenarios in this study were constrained to achieve zero CO_2 emissions by 2050 because this is not possible by focusing only on the electricity sector.

The resultant CO_2 emissions per scenario from 2023 to 2050 are shown in Figure 2. Scenario A achieves 123 Mt/a CO_2 emissions in 2030, which is generally considered within the current NDC range for the power sector. Scenarios B and C achieve 181 Mt/a CO_2 emissions in 2030, which, depending on the source, is either on the extreme upper end or above the NDC contribution for the power sector. Scenario A results in the lowest CO_2 emissions by 2050 (8 Mt/a).

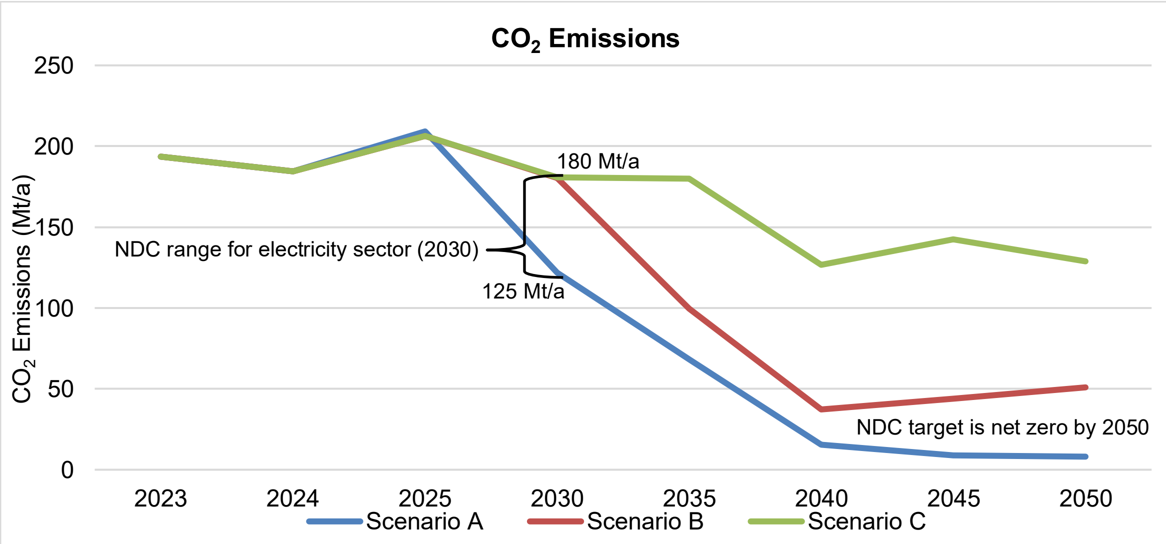

Figure 2: CO_2 Emissions per Scenario

Investment Required

The total investment required per scenario over the period from 2025 to 2050 is shown in Table 2. Even though Scenario A requires the largest up-front build of new energy generation and storage capacity, it results in the lowest total system investment[3] due to more optimistic technology learning rates and lower variable generation costs (because of less fuel being required, combined with lower fuel prices). Scenario

[3] Total system investment = Total generation investment (which is the sum of all generation and storage Capex, Opex, and fuel investments) plus Total grid investment (which is the sum of all transmission and distribution collector networks Capex investments).

C, although requiring the smallest up-front build of new power generation and storage capacity, results in the highest total system investment due to the least optimistic technology learning rates and higher variable generation costs.

Table 2: Total Investment Required per Scenario from 2025 to 2050 (R'bn, discounted 8% to 2024 real terms)

Investment detail	Scenario A (Green Industrialization)	Scenario B (Market Forces)	Scenario C (Business-as-usual)
Total Generation Investment	3 203	3 395	3 935
Total Grid Investment	383	262	231
Total System Investment	3 586	3 657	4 166

Scenario A requires the highest average annual investment from 2025 to 2030, due to the accelerated scale of new VRE and BESS capacity rollout during this timeframe, compared to scenarios B and C. Following this, Scenario A benefits from the lower variable generation costs and requires the lowest average annual investment from 2031 to 2050, compared to scenarios B and C.

Funding Gap: Soft Market Sounding Exercise Input

- **Quantum of funding available to solve for the funding gap:** Most of the market sounding participants indicated that there is no funding gap for energy infrastructure within the South African market over the short-to-medium term. However, local market sounding participants have indicated that a significant funding gap is expected over the longer term.
- **Pricing as a limitation to financing of renewable energy infrastructure:** Pricing is a significant barrier to the financing of renewable energy infrastructure in South Africa. This is primarily due to the highly competitive nature of the current generation infrastructure market. The same would not apply for transmission, as the market has not developed to the point where price discovery is market-driven.
- **Policy uncertainty as a limitation to allocating additional funding to renewable energy infrastructure:** The primary concern relates to the uncertainty and unpredictability of policies and frameworks related to transmission and distribution infrastructure, which is, in turn, a significant limitation for participants when allocating additional funds to energy infrastructure investments in South Africa.
- **Role of blended finance as an enabler of financing energy infrastructure in South Africa:** Identified as a potential mechanism to attract debt funding for investment within energy transmission infrastructure.

- **Role of credit enhancements in financing energy infrastructure in South Africa:** Local commercial banks have indicated that credit enhancements play a moderate role. At the same time, pension funds and IPPs have emphasised that the importance of credit enhancements in attracting debt funding.
- **Level of market risk in the current renewable energy infrastructure environment in South Africa:** Market sounding participants largely indicated that they have little appetite for taking on this market risk, as the wholesale market is currently not mature enough in South Africa.

Some of the additional themes identified during the market sounding included the following:

- **Limitations or obstacles in relation to raising or allocating additional funds towards energy infrastructure in South Africa as indicated by market sounding participants:** Programme inconsistency and the resultant lack of bankable projects; Eskom's inability to process the substantial number of applications for Eskom's Budget Quote (BQ) process; the Income Tax Act 58 of 1962 (as amended) Section 23M limitation on the deductibility of interest on debt; a lack of clarity for energy transmission infrastructure policy and framework; a lack of ability to execute construction of renewable energy projects; internal and external pressures from stakeholders to fund gas-to-power projects; uncertainty created by the government's draft IRP papers; and a lack of coordination by public stakeholders.
- **Key enablers or catalysts that would encourage additional capital formation and allocation of funds within the South African energy infrastructure sector as indicated by market sounding participants:** Education for private market sector and trustees of pension funds to encourage additional capital flows; increased alternative asset allocations by South African pension funds; National Treasury's guarantees provided to off-takers with lower credit quality; pilot projects within the transmission infrastructure sector to support large scale future rollout; development of a robust licensing and tariff regime; and innovative funding approaches.

Funding Gap Estimation

- **Significant funding gap:** Private funding attraction alternative is the ability of the market to attract private investment into energy infrastructure. Despite approximately R118 billion in annual available private finance and an overall (i.e., including the International Partners Group (IPG) loan and public sector funding) annual R127.6 billion during 2025 to 2027, the estimations suggest that there could still be a notable annual Capex funding gap (including grid costs) from 2025 to 2030 for Scenario A (Green Industrialization) and, to a lesser extent, for Scenario C (Business-as-usual) from 2028 to 2030 in the low funding attraction alternative.

- **Scenario results:** Given that the assumptions relating to the high and low funding attraction alternatives are the same for each scenario in each period, the extent of the Capex funding gap is directly determined by the Capex requirements. Specifically, this refers to the timing of Capex outlay requirements for the underlying technology mix and the associated learning rates of these sets of technologies. As can be seen in the last row of Table 3 below,

Table 3: Capex Funding Gap per Scenario and (Private) Funding Attraction Alternatives (R'bn p.a., discounted 8% to 2024 real terms, and % of GDP)

Scenario	Scenario A (Green industrialization)		Scenario B (Market Forces)		Scenario C (Business-as-usual)	
2025–2027	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**
Capex gap	12.5 (0.17%)		-58.4 (-0.80%)		-38.1 (-0.52%)	
2028–2030	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**
Capex gap	53.5 (0.73%)	44.0 (0.60%)	-17.4 (-0.24%)	-26.9 (-0.37%)	2.8 (0.04%)	-6.6 (-0.09%)
2031–2050	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**
Capex gap	-9.4 (-0.13%)	-21.2 (-0.29%)	-15.3 (-0.21%)	-27.1 (-0.37%)	-12.1 (-0.16%)	-23.9 (-0.33%)

- **Including Opex:** When including Opex, a funding gap exists for all scenarios, ranging between 1.10% and 1.87% of the GDP from 2025 to 2027 and 1.53% and 2.43% of the GDP from 2031 to 2050. From 2031–2050, Scenario A's Opex is lower than the Opex of the other two scenarios, which leads to this scenario having the lowest total funding gap from 2031 to 2050.

Regulatory Review

- While the Constitution underscores the implicit right to electricity as essential for upholding human dignity and socio-economic rights, it lacks explicit provisions on renewable energy adoption. However, when read together with Section 24 (b), the right to electricity implies the provision of pollution-free electricity, i.e., renewable energy.
- Key policies, such as the White Paper on Energy Policy of 1998 and the Draft South African Renewable Energy Masterplan (SAREM) (March 2022), outline strategic objectives but face challenges in formalizing funding mechanisms.
- The National Integrated Energy Plan, 2016 and Electricity Regulation Amendment Act 38 of 2024 propose decentralization and modernization but omit explicit funding provisions, potentially hindering infrastructure investment despite enhancing market competitiveness. There have however been recent changes to drive infrastructure deployment, whereby Regulation 28 under the Pension Fund Act 24 of 1956 defines infrastructure and sets a 45% cap for exposure in infrastructure investments, while increasing the private equity allocation to 15% from 10% by separating it from hedge funds. Additionally, a 25% limit has been imposed across all asset classes to restrict retirement fund exposure to any one entity, except for government-issued or government-guaranteed debt and loans.

- More strategic reforms are essential to align regulatory frameworks with evolving energy needs, ensuring a competitive, resilient, and sustainable electricity sector aligned with constitutional imperatives and global energy transitions.

Conclusions

Scenario A

- **Context:** Scenario A (Green Industrialization) assumes optimistic technology learning rates, lower fuel prices, a higher carbon tax, and a strong alignment with both local and global green industrialization objectives. It also includes a premium on the cost of capital for fossil fuel technologies (10%) and the earliest AQ compliance deadline (2030).
- **Results:** Scenario A involves the largest and most accelerated transition away from coal generation to variable renewable energy (VRE), battery energy storage systems (BESS), gas, and carbon capture and storage (CCS). This results in the highest up-front capital investment of R1 651 billion for generation; lowest operation, maintenance, and fuel investment of R1 552 billion; highest grid capacity investment of R383 billion; but the lowest total system investment of R3 586 billion by 2050. Grid investments comprise 11% of the total system investment, with 53% of these grid investments attributed to distribution collector networks.
- **Emissions:** Scenario A results in the lowest total CO_2 emissions of 2.1 Gt from 2023 to 2050, comfortably achieving the NDC target range for the power sector (120 to 180 Mt/a in 2030). By 2050, emissions are reduced to around 8 Mt/a – a level consistent with net-zero ambitions.
- **Challenges:**
  - High capital investment requirements, particularly for renewables and BESS.
  - Technical and institutional capacity to rapidly deploy and integrate these technologies.
  - Economic impacts of rapid coal decommissioning.
  - Deployment of CCS from 2035 for Medupi, Kusile, and Majuba, despite CCS currently being at a small-scale readiness globally.

Scenario B

- **Context:** Scenario B (market forces) represents a middle-ground approach, with moderate technology learning rates, medium fuel prices, and a carbon tax trajectory similar to Scenario A.

It includes a 5% cost of capital premium for new fossil fuel technologies and mandates AQ compliance by 2035.

- **Results:** This scenario sees a more gradual transition from coal to renewable energy, requiring the lowest generation Capex investment of R1 229 billion; R2 166 billion for operations, maintenance, and fuel; and R262 billion for grid expansion, with a total system investment of R3 657 billion. This is 2% higher than Scenario A. Grid investments represent 7% of the total system investment, with 47% of these investments going to distribution collector networks.
- **Emissions:** CO_2 emissions in 2030 reach 181 Mt/a, which is at the upper end of the NDC target range. Emissions decline significantly to around 51 Mt/a by 2050, potentially within future NDC targets for the power sector.
- **Challenges:**
  - Moderate investment requirements and a more measured infrastructure build-out pace.
  - Delayed CCS deployment (from 2040), with the same technology readiness concerns as in Scenario A.
  - Need for careful balancing of investment in renewables, BESS, and gas to avoid higher long-term system investments.

Scenario C

- **Context:** Scenario C (Business-as-usual) reflects a pathway with minimal global and local focus on emissions reductions and green industrialization. It is driven by pessimistic technology learning rates, higher fuel prices, and no cost of capital premium for fossil fuels. AQ compliance is not mandated.
- **Results:** Scenario C requires R1 446 billion for generation Capex investment; R2 490 billion for operations, maintenance, and fuel (the highest cost of the three scenarios); and R231 billion for grid Capex (the lowest cost of the three scenarios); resulting in the highest total system investment of R4 166 billion. This is 16% higher than Scenario A, due to persistent reliance on fossil fuels and slow renewable deployment. Grid investments make up only 6% of the total system investment, with 43% of these costs allocated to distribution collector networks.
- **Emissions:** Emissions in 2030 reach 181 Mt/a, which is again at the upper end of the NDC target range. By 2050, emissions remain high at 129 Mt/a, significantly above the net zero target.
- **Challenges:**
  - High reliance on coal and gas, with no CO_2 emissions or AQ compliance constraints.
  - Higher long-term system costs are driven by prolonged fossil fuel dependence.

- Limited incentives for renewables and BESS, increasing overall vulnerability to fuel price fluctuations and carbon-related export market barriers.

New power generation capacity: In all scenarios, the largest component of new power generation capacity consists of VRE technologies, such as solar PV and wind, supported by new BESS and gas generation capacity.

Secure and reliable supply: All scenarios achieve a secure and reliable supply of electricity, with no load shedding forecast beyond 2030, assuming the coal fleet meets the forecasted availability levels.

Grid expansion: Key corridors for grid expansion in all scenarios include the western, central, and eastern 765 kV corridors, aligning with Eskom’s Transmission Development Plan (TDP). The Northern Cape to Free State corridor envisages higher capacity than current plans, reflecting a longer-term focus in this study compared to the medium-term focus of the TDP and Strategic Transmission Corridors.

Funding Gap

- **Energy regulation and market reform:** The market sounding participants (financiers) detailed that regulatory, market, and project (supply) challenges could lead to a decline in private sector funding in the medium to long term. The Capex funding gap will therefore depend on how effectively South Africa can reform its local energy regulation and market to ensure a pipeline of investible energy infrastructure projects.
- **Closing the funding gap:** The required funds to address the funding gap will have to be sourced from the private sector and donor sources.
- **Tariff setting and collections:** While the tariff setting process considers various factors, including consumer affordability, if Eskom and the National Transmission Company South Africa (NTCSA) cannot collect sufficient tariff revenue for expansions, operations, and maintenance, the total funding gap could widen.

Regulatory Review

- **Fragmented Framework:** South Africa's regulatory landscape is fragmented and underdeveloped, posing significant challenges for financing and attracting sustained investment in energy infrastructure.
- **Lack of unified legislation:** The absence of a unified legislative framework prioritizing energy infrastructure as a national strategic investment area creates procedural uncertainty and deters investors.
- **Political commitment vs regulatory system:** Despite strong political commitment, South Africa's regulatory system is not robust enough to deliver investment at the required pace and scale.

- **De-risking energy projects:** South Africa lacks effective mechanisms to de-risk energy projects, such as government-backed guarantees and blended finance facilities, which are crucial for attracting large-scale investment.
- **International best practices:** Countries like Chile and India have adopted robust legal frameworks that enable independent power producers (IPPs) and provide regulatory certainty, which South Africa can learn from.
- **Integrated planning:** Successful jurisdictions use long-term infrastructure planning legislation supported by independent institutions to identify priorities, coordinate stakeholders, and facilitate investment.

Recommendations

1. On electricity infrastructure capacity expansion, consider the following:	**Primary responsibility**	**Secondary responsibility**
1.1 Scenario A: Pursue the green transition, energy mix, and investment pathway of Scenario A, as it meets NDC targets and requires the lowest total system investment. This depends on favourable socio-economic and global pathways; policies should aim to support these conditions.	Minister of Electricity and Energy	
1.2 Scenario B: If global and local contexts shift towards a less aggressive green transition, Scenario B could be justified for its lower annual Capex needs, despite the higher requirement of total system investment. However, broader climate risks may still favour policies aligned with Scenario A.	Minister of Electricity and Energy	
1.3 Scenario C: While Scenario C prioritizes least-cost electricity supply due to the assumed pessimistic global and local conditions, it results in the highest required total system investment and ignores climate targets. Even if global conditions align with Scenario C, South Africa should weigh these against climate impacts and consider transitioning towards scenarios A or B instead.	Minister of Electricity and Energy	
1.4 Significant expansion of VRE technologies: Focus on expanding VRE as part of the least-cost energy solution. To meet or exceed the NDC target by 2030: 7 GW/a (2025 to 2030). To achieve near-zero emissions by 2050: 5 GW/a (2031 to 2050).	Minister of Electricity and Energy	IPPs, Eskom (Generation)
1.5 Incorporate gas and battery storage to support VRE technologies: Expand BESS capacity for short-term support. Establish and expand gas supply infrastructure and new gas generation capacity for longer duration VRE support (i.e. peaking operation, not baseload).	Minister of Electricity and Energy	IPPs, Eskom (Generation)
1.6 No new coal and nuclear plants: Avoid new coal and nuclear capacity to achieve the least-cost energy mix, as indicated by multiple studies, including this one.	(Department of Electricity and Energy) DEE	
1.7 Air quality (AQ) retrofits only for plants with longer remaining life: Decommission coal plants with shorter remaining life instead of	Eskom (Generation)	

deploying AQ retrofits. Conduct a thorough cost-benefit analysis before investing in AQ retrofits.		
1.8 Investigate and monitor the feasibility of CCS technology: Monitor CCS technology for future feasibility and cost-effectiveness. Its deployment depends on global adoption rates and maturity.	Eskom (Generation)	
1.9 Maintain existing infrastructure: Ensure existing coal fleet meets availability targets and transmission infrastructure is reliable to achieve energy security and reliability.	Eskom (Generation), NTCSA, Municipalities	
1.10 Decentralized energy systems: Implement renewable energy-based microgrid systems for rural communities to improve the quality of life and create job opportunities.	DEE	National Energy Crisis Committee
1.11 Co-locate renewable energy generation infrastructure with demand: Reduce transmission losses and improve energy efficiency by co-locating renewable energy infrastructure with demand centres like industrial parks and urban areas.	NTCSA	Industrial Development Corporation of South Africa
1.12 Disruptive technologies: Monitor the development of new technologies in the electricity sector, as discussed in Appendix E.	NECOM and Industry Bodies	
2. Expedite regulatory and market reform: Considering and improving the specific items below, as highlighted by the market sounding participants, could assist in attracting investment and reducing the funding gap over the long term for investment in the South African energy infrastructure market:	DEE, NTCSA (Market Operator)	
2.1 Debt funding instruments and products need to be repriced to ensure liquidity and long-term participation from the secondary market, given sector exposure limits from local commercial banks.	Commercial Banks, Development Banks	Johannesburg Stock Exchange (JSE)
2.2 Improved clarity and consistency when developing renewable energy infrastructure programmes and policies (such as the coal fleet decommissioning schedule) to ensure a pipeline of bankable projects is developed over the long term.	Independent Power Producer Office (IPPO), DEE	
2.3 National Treasury-backed guarantees or similar guarantee-type vehicles, such as a World Bank Guarantees Program, with an	National Treasury	

appropriate mix of grant, concessional (i.e., climate finance), and market-related funding to bring down the overall cost of capital, will unlock private sector capital, as well as assist in the development of the pipeline of bankable projects.		
2.4 The development of a wholesale energy market should be finalized from a market risk perspective, creating liquidity and pricing certainty that would encourage additional market participation from power producers, consumers, and financial institutions.	NTCSA (Market Operator)	
2.5 Improved efficiency by Eskom to process more Budget Quotes (BQs) as the market continues to grow.	Eskom (Generation)	
2.6 Implement policies and frameworks and develop bankable commercial structures with suitable guarantees to encourage the funding and implementation of the **transmission programme**.	DEE	NTCSA
2.7 Reindustrialization and capacitation of technical skills to support the energy infrastructure construction market, as well as for engineering, procurement, and construction (EPC) contractors.	Department of Trade, Industry and Competition (DTIC), IDC	
2.8 Improved coordination of various public stakeholders to ensure projects can progress to bankability and implementation.	Department of Cooperative Governance and Traditional Affairs (CoGTA)	
2.9 Promotion and education of pension funds relating to alternative asset classes, i.e., infrastructure sector, to encourage additional capital formation and allocations from the private sector from 2% to potentially 5% to align with international norms.	DFIs, Consultants	Pension Funds
2.10 Promotion of innovative funding solutions, including the private funding of transmission, REIT-type vehicles, EPC guarantees, swaps on ZAR-based lending, longer debt tenors, alternative funding, and operating models (i.e., public-private collaboration).	Development Banks, Commercial Banks	JSE
2.11 Reformation of the municipal energy distribution infrastructure framework could attract additional funding from	CoGTA, National Treasury	South African Local Government

potential funders for energy generation and distribution infrastructure, as it will open and grow the energy market.		Association (SALGA)
3. On policy and regulatory reform, consider the following:	**Primary responsibility**	**Secondary responsibility**
3.1 Use of a Renewable Energy Fund: Introduce a surcharge, like Germany's Erneuerbare-Energien-Gesetz (EEG) or Renewable Energy Sources Act, to fund clean energy projects, ensuring fairness for low-income households and equitable cost-sharing. Complement this with grid upgrades, storage investments, and demand-side management, integrating the surcharge into existing tax systems.	National Treasury	DEE
3.2 Introduce tax incentives: Offer tax breaks similar to the US's ITC and PTC to lower upfront costs and reward energy production, driving renewable energy investment and growth.	National Treasury	SARS
3.3 Introduce targeting mechanisms: Mandate municipalities to source a set percentage of electricity from renewables, with flexible targets and timelines. Use renewable energy certificates for compliance and incentivize investments through supportive legislation.	National Treasury, DEE	CoGTA
3.4 Use of pricing and returns incentives: Create capacity and ancillary services markets to ensure reliable power supply and grid stability, with fair, transparent incentives for availability, generation, and stability services.	NTCSA (Market Operator)	
3.5 Use of deemed energy payments: Protect IPPs against network risks by enforcing NERSA rules and adopting models like Morocco's Grid Access Agreements, ensuring compensation for undelivered energy due to grid issues.	NERSA	
3.6 Relocate Eskom's Grid Access Unit (GAU): • **Reduced conflict of interest:** Separate the GAU from Eskom Distribution to minimize conflicts and ensure objective decisions on grid connections. • **Improved efficiency:** An independent GAU can streamline processes, reduce delays, and lead to faster project approvals and innovative grid management solutions, and	Eskom (Distribution)	NTCSA

• **Enhanced collaboration:** Direct access to resources and authority improves coordination and the progression of technical designs and user requirements for grid connections.		

Section A: Introduction, Approach, and Pathways Development

1 Introduction

In 2012, the National Development Plan (NDP) was promulgated to outline goals that various sectors in South Africa, including energy and infrastructure, are to achieve by 2030, with the aim of alleviating load shedding and stimulating economic activity (NPC, 2012). In 2015, all United Nations (UN) member countries adopted the 2030 Agenda for Sustainable Development, which sets out 17 Sustainable Development Goals (SDGs), including Goal 7, which aims to ensure access to affordable, reliable, sustainable, and modern energy for all. In the same year, the Paris Agreement was adopted by several countries globally to mitigate carbon emissions. As of April 2025, 198 member states of the United Nations Framework Convention on Climate Change (UNFCCC) are parties to the Paris Agreement. Included in the Paris Agreement are the Nationally Determined Contributions (NDCs), which represent each member state's commitment towards mitigating national emissions and its efforts to adapt to climate change.

A partnership was formed between the Development Bank of Southern Africa (DBSA), Presidential Climate Commission (PCC), the National Planning Commission (NPC), and the National Treasury via its programme Southern Africa – Towards Inclusive Economic Development (SA-TIED) to assess the level of investment required between 2024 and 2030, and onwards to 2050. The partnership aims to achieve the SDGs, NDP commitments, and National Infrastructure Plan (NIP) 2050 ambitions in the energy sector, while considering the NDC emissions window within which South Africa pledged to achieve in the Paris Agreement in September 2021. To explore these pathways and implications further, the partnership appointed a project team, led by PwC and supported by Osmotic Engineering Group (OEG), for this work through a Request for Proposal (RFP) process.

The work covered in this report relates to pathways development, energy[4] infrastructure and power systems (technical) modelling, soft market sounding, funding gap estimation, and regulatory review. This report is supported by a literature review (DBSA, National Treasury, NPC, PCC, 2025b) to inform the analysis, which allows for a results comparison. Additionally, a socio-economic impact modelling study has been completed using the scenario output from this study's technical modelling and will be published in a supplemental report (DBSA, National Treasury, NPC, PCC, 2025c).

[4] *For the purposes of this report, 'energy' is defined as electricity, encompassing renewable sources, coal, gas, uranium, and diesel. From an infrastructure perspective, the report deals with electricity generation, storage, transmission, and distribution infrastructure. Upstream infrastructure for the supply of coal, gas, and diesel fuels is incorporated in the unitised cost of these energy sources as they are consumed by the associated electricity generation plants, i.e., the study does not estimate the capital costs required for upstream infrastructure such as gas pipelines, liquefied natural gas (LNG) terminals, petrochemicals manufacturing, coal mines, etc.*

This work will also form part of the broader SA-TIED Workstream 5 relating to Water-Energy-Food in the context of Climate Change. This study does not directly address Water-Energy-Food nexus issues, but it forms part of the groundwork for ongoing research on this topic.

At the time of writing, the IRP2019 and Draft IRP2023 were published, with the knowledge of a Draft IRP due later in 2025. The technical modelling approach for this study is broadly similar to that used for previous IRPs. In addition, the demand forecast assumption for this study is the same as the demand forecast used in the Draft IRP2023. This study involved three main scenarios, each based on a least-cost optimization, but with differing input variables, including carbon budgets, carbon tax, technology costs, fuel costs, and the cost of capital. While many of the input variables are similar to the Draft IRP2023, the combination that formulates each scenario in this study differs from past IRP scenarios and may differ from the Draft IRP2025. The intention of the modelling conducted in this study is to contribute to the body of literature in the electricity sector and to elicit discussion on the most optimal and practical energy and carbon pathways for South Africa.

1.1 South African Electricity Governance and Operational Structure

The South African electricity landscape is dominated by Eskom Holdings SOC Ltd (Eskom), a state-owned utility. The South African Energy White Paper finalized in 1998 envisaged a gradual transition to a competitive power industry, with the end state for the industry including separate and competing generation companies, an independent transmission company, and separate retail distribution entities. The vision of this policy was not translated into an industry blueprint or legislation, leaving the electricity supply industry unchanged, while most other countries proceeded with liberalization.

The Government has more recently embarked on a process to unbundle the vertically integrated Eskom into three subsidiaries: generation, transmission, and distribution, still wholly owned by Eskom. The unbundling of Eskom is viewed as a key step in the transition of the country's electricity supply industry, with one key outcome being the financial separation of the transmission entity from Eskom or 'ring-fenced' to encourage renewed investment.

Efforts are currently underway to achieve this change in the structure of the electricity supply industry in South Africa. The first is the unbundling of Eskom, as outlined in the Roadmap for Eskom in a Reformed Electricity Supply Industry, released in October 2019 (Department of Public Enterprises (DPE), 2019). In 2023, Eskom applied for an electricity transmission licence, an electricity trading licence, and an electricity import and export licence in terms of the Electricity Regulation Act of 2006 that would enable the transfer of the transmission business of Eskom to the National Transmission Company South Africa SOC Ltd (NTCSA). NTCSA is a juristic entity and a state-owned company that is wholly owned by Eskom. The NTCSA transmission licence application includes the following services currently contained in the existing Eskom transmission licence:

- The Transmission Network Service Provider,
- The System Operator,
- Transmission System Planner, and
- Grid Code Secretariat function.

The National Energy Regulator of South Africa (NERSA) granted the NTCSA a transmission licence in July 2023, and the entity commenced separate operations in July 2024. The establishment of the transmission company (NTCSA) is a step towards the unbundling of Eskom and could lead to a competitive energy generation sector, where multiple electricity producers sell to the national grid and various private customers.

The details of the vision for the future energy market, end state of the industry, and implications for current stakeholders remain unclear. A comprehensive and agreed framework is not yet available, and there appears to be a conflicting understanding of market requirements. The role of the NTCSA, as it performs a traditionally independent function in reformed markets, is set out in the Electricity Regulation Amendment Act to include:

- Grid owner and operator of physical assets,
- System Operator (such as National Control),
- Market Operator (enables the trading of electricity),
- Central Purchasing Agency (CPA) (the entity that will inherit legacy Independent Power Producer (IPP) power purchase agreements (PPAs) and Eskom Generation purchases, as well as conclude new IPP PPAs for centrally procured power instead of Eskom), and
- International Trader.

Several other factors also affect the energy market transition, including the development of market rules and other details needed to transition to a wholesale market. As the process of transition unfolds, the question also needs to be addressed as to what type of wholesale market-driven power sector is most suitable as a desired end state, and whether a hybrid system has merit, considering South Africa’s unique circumstances. Currently, changes to legislation do not provide insight into the intended end state of the retail energy market.

1.2 South African Electricity Infrastructure Contextual Overview

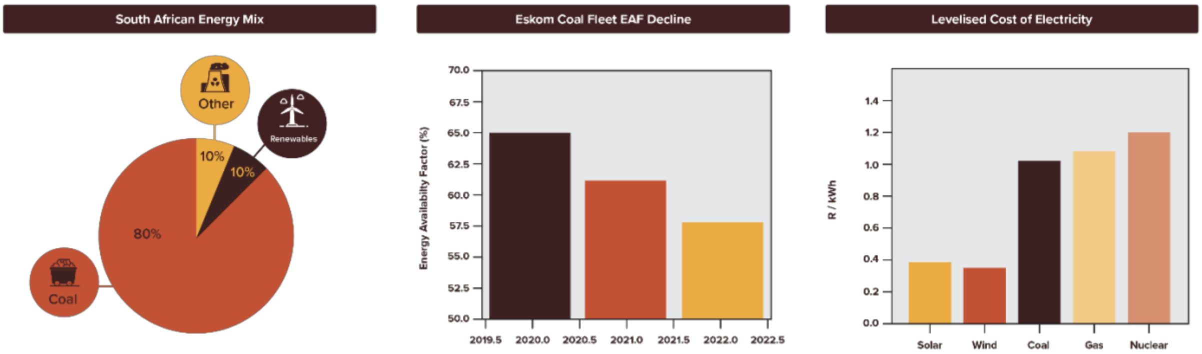

Figure 3: South Africa's Electricity Landscape: Key Figures

Source: Fitch Solutions (2024)

Affected by the disruptive nature of the COVID-19 pandemic and heightened geopolitical tensions, nations are turning inwards to address emerging and persistent challenges, particularly the interconnected issues of energy security and climate change. South Africa, like several other developing nations, has a fossil fuel-intensive energy sector, which compounds the triple challenges related to accessing green electrons, i.e., the cost of domestic electricity, the inability to access renewables as a form of low-cost power, and being locked into fossil fuels, particularly coal.

As indicated in Figure 3, coal dominates South Africa's energy mix, with 80% of electricity being generated via coal plants. These plants are predominantly owned and operated by Eskom, with the utility generating approximately 95% of the electricity used in South Africa, equivalent to 45% of the electricity used on the African continent. It directly provides electricity to 45% of all end-users in South Africa, while the other 55% is resold by redistributors (including municipalities) (Fitch Solutions, 2024).

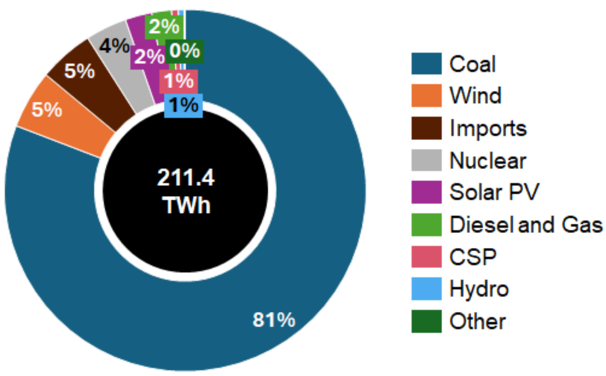

Figure 4: South Africa's Annual Energy Mix

Source: Centre for Renewable and Sustainable Energy Studies (CRSES) (2024).

South Africa's reliance on coal to provide baseload energy is an artifact of its historic industrialization strategy, which focused on the mineral-energy complex. Previously, this served to develop South Africa into one of the leading economic powerhouses on the continent. However, the surging demand for reliable and affordable energy, the Nation's ageing coal fleet, and Eskom's weak financial position, have severely constrained the South African energy sector.

The degradation of Eskom's coal fleet is evident and quantifiable using the annual average energy availability factor (EAF). Eskom's EAF has exhibited an average linear decline of 3.8% per annum from 2018 to January 2023 (Eskom, 2024a). The average EAF of the Eskom coal fleet declined from 65% in 2020, 61.7% for 2021, and 58.1% in 2022. After significant planned maintenance from the end of 2023 to the beginning of 2024, and the return to service of new units at Kusile from January 2023 to January 2024, the year-to-date EAF showed a positive trend, moving from 50% to 55%. During the 2024 calendar year, the average EAF was 59.78% (Eskom, 2025). This falls within the range captured in the Draft Integrated Resource Plan (IRP) published in December 2023, which has a low EAF scenario between 50% and 52% and a high EAF scenario between 65% and 69%.

The supply and demand imbalance in South Africa's single buyer energy model has led to load shedding continuing during 2023, where load shedding reached its highest levels. Load shedding describes the practice of rationing energy across the grid to prevent a demand-driven nationwide blackout. While 2024 showed significant improvement, the country experienced 335 days of load shedding in 2023, with an estimated negative economic impact of R230 billion (Loewald, 2023). To meet the energy needs of a transformed energy landscape in alignment with the objectives of Eskom's coal plant decommissioning schedule, the Just Energy Transition Investment Plan (JET IP) proposes that 50 Gigawatts (GW units) of new renewable energy capacity must be added to the grid over the next 22 years. However, to achieve the lower end of the NDC target of reduced emissions, 50 GW of renewable energy capacity should be brought online by the end of 2030 (The Presidency, 2022). The now outdated IRP 2019 envisaged the addition of approximately 30 GW of renewable electricity capacity being brought online by 2030, including 2.5 GW of imported hydro capacity from the region (Department of Mineral Resources and Energy (DMRE), 2019).

The electricity sector's reliance on coal for electricity generation makes South Africa one of the world's major greenhouse gas (GHG) emitters, with South Africa ranked among the top 20 countries measured by absolute carbon dioxide (CO_2) emissions. According to the European Commission's Emissions Database for Global Atmospheric Research (EDGAR) (2024) report on global GHG emissions, South Africa's share of global emissions was 0.99% in 2023, at 522.12 metric tons of carbon dioxide equivalent ($MtCO_2e$). This positions South Africa as the top GHG emitter in Africa and 19th globally.

Climate change is currently altering South African ecosystems, economies, and the livelihoods of its people. According to the Department of Forestry, Fisheries and the Environment (DFFE), climate change has already led to extreme weather events, including droughts, floods, and rainfall fluctuations, which have impacted the economy, infrastructure project development, and the lives of many citizens (DFFE, 2022).

The combination of reduced VRE (and storage) technology prices and households or companies seeking to overcome load shedding has contributed to South Africa's decarbonization progress. The mineral-energy backbone of South Africa's commodity trade is expected to be parameterised by international markets through focused trade legislation that penalises or restricts imports from carbon-heavy markets. Cognisant of the carbon-related policy changes to key trading blocs, the realized impacts of fossil fuels towards exacerbating climate change, and obligations to global climate compacts, such as the Paris Agreement, South Africa is trying to transition the energy sector away from its heavy reliance on coal.

1.2.1 South Africa's Nationally Determined Contributions (NDCs)

South Africa's Climate Change Act was promulgated in July 2024. This legislation outlines the national climate change response, including mitigation and adaptation strategies. Furthermore, the NDCs detail South Africa's contribution to the global climate change response.

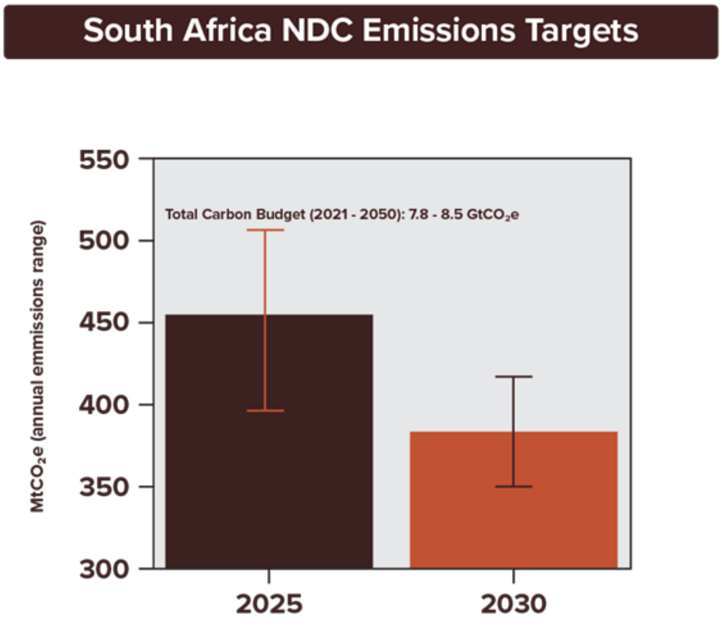

Figure 5: South Africa's NDCs

Source: RSA: NDC (2021)

Estimates from the South African National GHG Inventory Report puts the latest total national emissions at approximately 436 $MtCO_2e$ during 2022 (DFFE, 2024). The country's national commitments for achieving climate goals are outlined in the NDC, recommended by the PCC and adopted by the government for submission to the UNFCC as an updated and more ambitious NDC in September 2021.

South Africa aims to achieve a peak, plateau, and decline (PPD) trajectory for its emissions. Specifically, South Africa has set targets to limit its annual GHG emissions to between 398 and 510 $MtCO_2e$ by 2025, and 350 and 420 $MtCO_2e$ by 2030, commitments that require an economy-wide transition and an associated enabling environment. This carbon budget represents South Africa's fair share of emissions to ensure the globe stays withing a 2°C warming range as per the Paris Agreement (RSA: NDC, 2021).

1.2.2 South Africa's Commitment to a Just Energy Transition (JET) through SDG 7 and National Development Plan (NDP) (Chapter 5)

The JET IP is aligned with the updated NDC emissions targets (The Presidency, 2022), and shows that a net-zero CO_2 goal will be achieved in 2050, with an overall GHG emissions budget of 7.8–8.5 $GtCO_2e$ between 2021 and 2050.

However, decommissioning the coal fleet will affect the country's fossil fuel-related industries, coal in particular, upon which the livelihoods of many communities depend. Beyond the 113 000 direct jobs in the coal industry, there are indirect jobs associated with the coal value chain, including mining, beneficiation, and generation, and additional jobs related to these activities. This indicates that without any intervention (as outlined in the JET IP), up to 450 000 coal-related jobs in South Africa would be at risk if the coal industry were to be eradicated (PwC, 2021).

The National Treasury (2023) estimates that load-shedding reduced real gross domestic product (GDP) growth by up to 2% in 2022. Despite the challenges, South Africa must aim to ensure an energy transition that achieves energy security at the least cost.

Box 1: Specific SDGs and NDP (Chapter 5) Objectives

The SDGs are a set of 17 global goals adopted by the United Nations (UN) in 2015 as part of the 2030 Agenda for Sustainable Development. These goals were set up to address various social, economic, and environmental challenges and guide global efforts towards a more sustainable, equitable, and prosperous future for all. The National Development Plan (NDP) 2030 is a comprehensive, long-term vision and strategy designed to address various socio-economic challenges in South Africa. It was introduced by the country's government in 2012 and spans 18 years, envisioning the country's growth and development up to 2030.

SDG 7 sets as a goal the provision of clean and affordable energy, with several targets as part of this overall goal. The first three listed here are outcome targets, while the final two are means of achieving these targets.

- **SDG 7.1**: By 2030, ensure universal access to affordable, reliable, and modern energy services. The NDP's focus is on expanding access to electricity and improving energy infrastructure to meet the needs of underserved and rural communities.

- **SDG 7.2:** By 2030, increase substantially the share of renewable energy in the global energy mix. The NDP supports the development and adoption of renewable energy sources as part of a transition to a more sustainable energy system.

- **SDG 7.3:** By 2030, double the global rate of improvement in energy efficiency. The NDP aims to improve energy efficiency across sectors to reduce energy consumption and lower GHG emissions.

7a International Cooperation

Enhance international cooperation on clean energy research and technology

- **SDG 7a:** By 2030, enhance international cooperation to facilitate access to clean energy research and technology, including renewable energy, energy efficiency, and advanced and cleaner fossil-fuel technology, and promote investment in energy infrastructure and clean energy technology. The NDP encourages investment in energy innovation and infrastructure to drive economic growth and development, aligning with broader goals of industrialization and economic transformation.

7b Infrastructure & Technology

Expand infrastructure and upgrade technology for sustainable energy services

- **SDG 7b:** By 2030, expand infrastructure and upgrade technology for supplying modern and sustainable energy services for all in developing countries, in particular least developed countries, small island developing States, and land-locked developing countries, in accordance with their respective programmes of support (United Nations, 2023). The NDP envisions a diversified energy mix that includes cleaner energy technologies and infrastructure investments to support long-term sustainability.

Specific to electricity, the NDP has the goal of raising the proportion of people with access to the electricity grid to at least 90% by 2030, with non-grid options available for the rest. This degree of electrification must occur in tandem with the procurement of at least 20 000 MW of renewable electricity by 2030, importing electricity from the region, decommissioning 11 000 MW of ageing coal-fired power stations, as well as increasing overall investments in energy efficiency (NPC, 2012).

The JET IP, grounded in the NDP, maintains that investment in renewable energy must support both energy security and decarbonization. The plan seeks to contribute to the achievement of national and regional economic goals, including immediate measures to manage fiscal constraints and address the energy supply crisis which leads to varying levels of electricity load shedding.

As stated in the JET IP, the electricity technology mix will be influenced by access to innovative, low-cost, green financing solutions. Public and private sectors, along with the international community, must develop blended finance mechanisms to unlock private sector funding. Mechanisms must be sourced to de-risk early-stage pilots, including contracts for difference (CfD)[5], price subsidies to bridge the affordability gap, and grant funding.

South Africa's relatively high electricity connection rate of 86.5% (United Nations Statistics Division (UNSD), 2023) does not directly translate to affordability. In addition, some unelectrified areas persist in both rural areas and new informal settlements. Access to electricity is critical to ensure human development, alleviate poverty, and reduce inequality.

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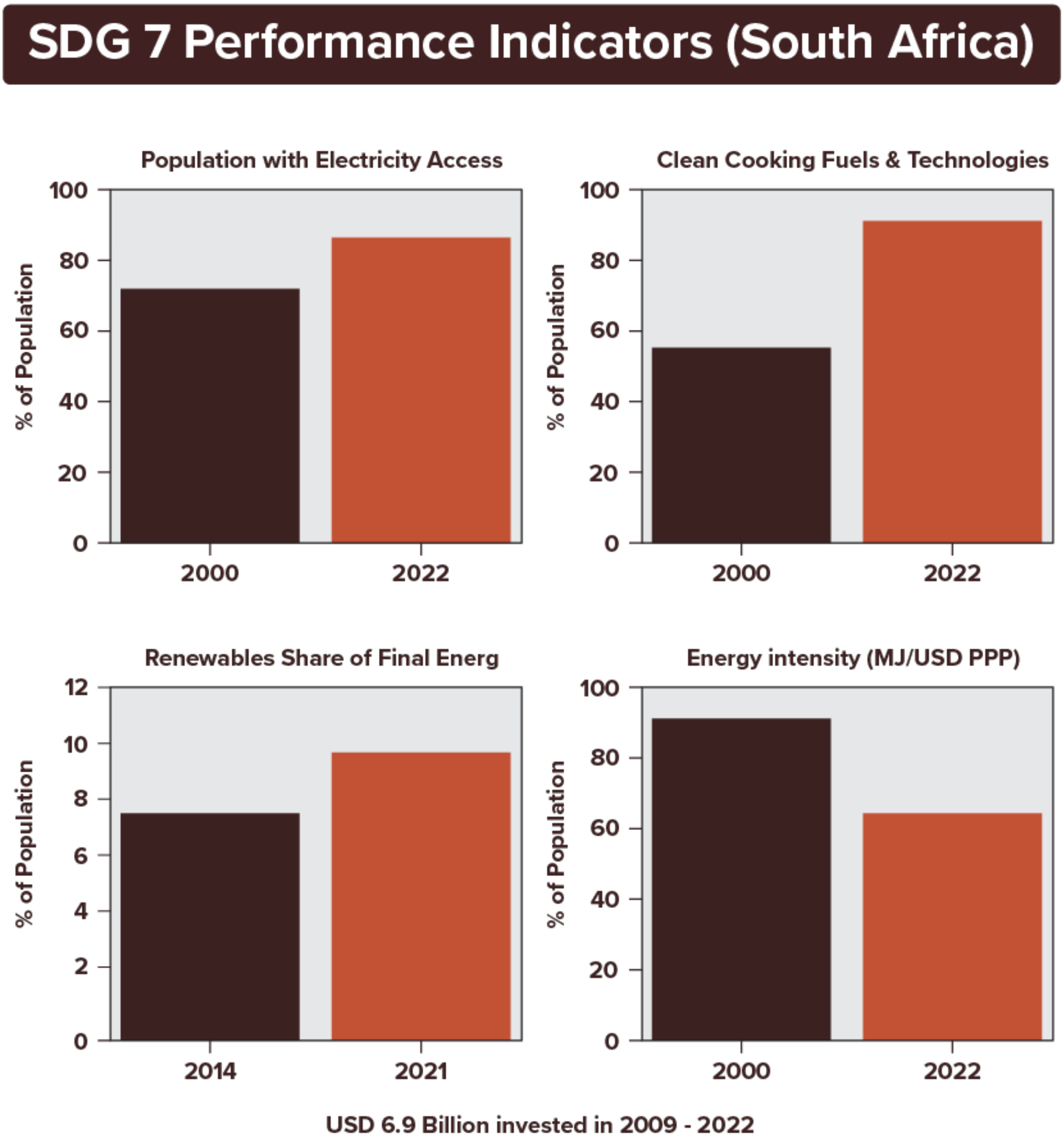
[5] *Financial agreements where the buyer and seller exchange the difference between the value of an asset at a specific future date and its value at the time the contract was initiated (meaning, if the current price is higher, the buyer gets paid the difference; if the current price is lower, the buyer pays the seller the difference). This mechanism helps to stabilise prices and provides financial certainty, making it easier to attract private sector funding for renewable energy projects. By de-risking early-stage pilots and bridging the affordability gap, CfDs play a crucial role in developing innovative, low-cost, green financing solutions.*

Box 2: South Africa's Performance on SDG 7-Related Indicators



1.2.3 Energy Sector Developments

The development of the energy sector is guided by a comprehensive and evolving policy and regulatory framework. Some notable recent changes are those in the Electricity Regulation Amendment Act and the Amended Schedule 2 of the Act that removed the licensing threshold of 100 MW for private generation. The key focus of the former is to establish a wholesale electricity market in line with international best practice, and the latter exempts any generation facility from requiring a generation licence. Interventions to reform the electricity regulation regime are a step towards unlocking significant investment in new power generation capacity in the short to medium term. They will assist in achieving national energy security, as well as reducing the adverse impacts of load shedding nationwide.

Variable renewable energy (VRE) is the industrialization trajectory for South Africa's JET that is the least financially costly. However, the shift from one mode of energy generation to another, the actual national absorptive capacity, and a misaligned pace of deployment for new transmission grid infrastructure in relation to VRE, indicate that investment instruments need to be dynamic and robust.

South Africa's JET IP has identified an overall quantum of R1.5 trillion worth of infrastructure investment needs up to 2035, with R711.4 billion alone ring-fenced for the electricity sector. Accordingly, there is a widespread view that South Africa has tremendous potential to achieve a just transition. However, the maturing of an enabling policy environment and the expansion of infrastructure to facilitate such a transition will be critical to actualize the growth opportunities emerging from the reforms currently underway. The section below outlines how policy and regulatory activations can realize such a transition and the associated growth opportunities.

The South African energy landscape is undergoing rapid change and reform, as ensuring energy security is urgent. As a testament to the government's commitment to address the energy crisis and foster the enabling environment to do so, South Africa has seen more regulatory reforms in the last three years than in the previous three decades. The implemented and proposed changes have resulted in many opportunities in the energy sector:

- **Renewable energy technologies** provide the least-cost avenues to generate electricity: In South Africa, the cost of solar reached R0.375 per kilowatt-hour (kWh) and R0.344 per kWh for wind in 2021 (Van Diemen, 2023). In comparison, the costs to generate electricity from coal, gas, and nuclear are approximately R1.03 per kWh, R1.11 per kWh, and R1.24 per kWh, respectively (Council for Scientific and Industrial Research (CSIR), 2016).
- Eskom continues to support solar adoption by **waiving registration fees** and providing free smart meters for residential Small-Scale Embedded Generation (SSEG) systems up to 50 kVA until March 2026. This policy aims to encourage households to invest in solar photovoltaic (PV) systems and support the transition to renewable energy (DFFE, 2025).
- **Battery energy storage systems (BESS)** have been introduced to support the roll out of renewable energy technologies, the possibility of establishing South Africa as a Green Hydrogen exporter with access to key export markets, and the opportunity to explore more efficient gas-to-power options and dispatchable power options connected via a smart grid, all could become attractive opportunities towards South Africa's net-zero goals by 2050.

- **Power market reform:** Over the last two years, South Africa has seen numerous commitments to accelerating the reform of the power sector. Reform implementation is being coordinated by a National Electricity Crisis Committee (NECOM) chaired by the Director General in the Presidency. With the Committee spearheading the reform, it has encouraged participation from all relevant departments and will draw on outside expertise. The power sector reform will require market infrastructure development (i.e., tariffs, licensing and registration, wheeling, and trading frameworks), as well as a fully-fledged power exchange (as envisaged as part of the Eskom unbundling process), to fast-track the growth of all market segments. Sector coupling will also occur due to the reform (including EVs, green hydrogen, and ammonia), which will lead to substantial growth in electricity demand and associated energy infrastructure.

These opportunities come with certain development areas that would need to be addressed to realize South Africa's energy potential:

- **Material expansion of the power grid:** The urgent need for investment in South Africa's grid infrastructure, as highlighted by the Transmission Development Plan (TDP) and updated Implementation Plan, presents a remarkable opportunity. In February 2023, areas with abundant renewable energy resources, like the Cape provinces, faced significant grid capacity constraints. By strategically directing resources towards enhancing the grid, South Africa can harness its renewable energy potential, drive economic growth, and establish a sustainable energy future.
- **Ramp-up decentralization efforts:** South Africa is making progress towards a more decentralized electricity sector, particularly when considering the recently promulgated Electricity Regulation Amendment Act 34 of 2004, which came into effect on 1 January 2025. The Act is part of a broader policy shift towards decentralization and increased private sector involvement in South Africa's electricity sector. However, it will take time to leverage the provisions of the Act to unlock the potential for decentralization. These legislative and policy changes are crucial for addressing South Africa's electricity challenges and ensuring a more reliable and sustainable energy future. Additionally, the shift towards more integrated electricity systems and new energy solutions has seen a growing number of consumers generating and distributing their own energy via the installation of small-scale embedded generation (SSEG). However, the implementation of SSEG frameworks with associated tariffs is a precondition for the efficient integration of prosumers into the electricity system.

1.3 Project Scope

Against this background, DBSA, the NPC, the PCC, and the SA-TIED programme partnership appointed a project team led by PwC, and supported by OEG, to assess the energy infrastructure investments needed to achieve the energy objectives in South Africa related to the NDCs and SDGs and linked to the NDP (Chapter 5) as well as the NIP 2050.

To answer the primary research question, the following supplementary questions will also be addressed:

1) What are the barriers to achieving SDG 7.1 (universal access to affordable, reliable, sustainable, and modern energy services) and associated NDP goals, and what needs to be done?
2) Given the probable impacts of climate change on the global commitment to decarbonization over the coming decades, what should the financing targets be for optimizing achievement of the energy and carbon SDGs and NDP goals by 2030, and extended to 2040 and 2050?
3) What is the funding gap between current levels of investment in energy infrastructure and what will be required to achieve the relevant energy and carbon SDGs, NDP, and NDC goals, covering new capital, operations, and maintenance spending?
4) What policy and regulatory frameworks are in place that govern the flow of public and private investments in energy infrastructure and service delivery with respect to technologies, service levels, and resilience in the face of climate change?
5) What PIR changes will be required to enable an increased level of investment in climate-resilient energy infrastructure and services to achieve the NDP and SDG targets?
6) How can the reliability of power supply, which disproportionately affects poorer households, be improved to meet SDG targets and NDP objectives, while being aligned to the Just Transition Framework (JTF)?
7) Is there a trade-off between the SDG 7 targets, NDP targets, sectoral targets, and the NDC commitments, and if so, what are they?
8) What will be the expected contribution of the existing IRP 2019 to SDG 7.2?
9) What would be the expected contribution of investment in transmission, according to the Eskom TDP, in terms of supporting SDG 7?
10) What would be the expected contribution of disruptive innovations on SDG 7.2 and SDG 7.3?
11) What would be a cost-effective path to achieve SDG 7.1 based on existing service standards?

The project team, among other aims, has quantified various scenarios and energy infrastructure investments, conducted a soft market sounding of potential financiers within the electricity landscape, estimated a funding gap range, and completed a PIR analysis related to the electricity and financing landscape. In a supplementary report, the team will produce a high-level economic and socio-economic impact assessment via a CGE model.

To support these outcomes, the team has conducted a separate, parallel literature review that covers the 11 questions. See Appendix F for a mapping of the research questions to report sections.

2 Approach

2.1 Adapted 'Beyond the Gap' Methodology

The World Bank 'Beyond the Gap' methodology (see Rozenberg and Fay, 2019) was applied, with two additional steps. The methodology can be broken down into the following steps, as shown in Figure 4:

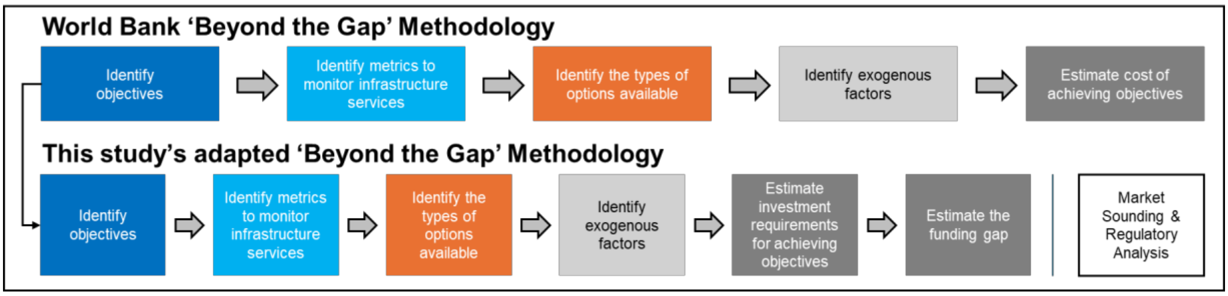


Figure 6: Adapted 'Beyond the Gap' Analytical Framework

Source: Rozenberg and Fay (2019).

- **Identify objectives:** The objectives for this study pertain to the need to achieve energy security at least cost, while meeting South Africa's NDC targets. Apart from the NDC targets, these objectives also directly affect South Africa's SDGs, specifically SDG 7, and are linked to the NDP (Chapter 5). These objectives are represented through the following metrics:
  - **Energy security and affordability objectives:**
    - Achieve 90% electricity access to all areas by 2030, with non-grid options available for the remainder (RSA, 2021).
  - As per SDG 7.1, ensure universal access to affordable, reliable, and modern energy services by 2030.
  - **Climate objectives:**
    - Reduce annual carbon emissions to 398–510 $MtCO_2e$ by 2025, and 350–420 $MtCO_2e$ by 2030 in line with South Africa's NDC targets.
    - As per SDG 7.2, increase the share of renewable energy in the global energy mix substantially by 2030. The NDP supports the development and adoption of renewable energy sources as part of a transition to a more sustainable energy system.
    - As per SDG 7.3, double the (global) rate of improvement in energy efficiency by 2030. The NDP aims to improve energy efficiency across sectors to reduce energy consumption and lower GHG emissions.

    - The NDP aims to procure at least 20 000 MW of renewable electricity by 2030, import electricity from the region, decommission 11 000 MW of ageing coal plants, and increase overall investments in energy efficiency (RSA, 2021).

- **Identify the metrics to monitor infrastructure services:**
  - **Electricity access:** The share of South Africans with access to grid power is currently estimated to be 86.5% (UNSD, 2023).
  - **The contribution of renewable energy to the country's total energy portfolio:** In 2021, this figure stood at 9.7% (UNSD, 2023).
  - **Energy efficiency:** In 2021, the ratio between energy supply and economic output was 6.6 megajoules per constant USD 2017 purchasing power parity GDP (MJ/USD 2017 PPP GDP) (UNSD, 2023).
  - **Electricity availability factor (EAF):** For the 2024 calendar year, South Africa's average EAF was 59.78% (Eskom, 2025).
  - **Affordability of technology options:** This metric will be expressed as a per annum cost for capital and operational expenditure (Capex and Opex) in 2024 real terms, comparable across the various scenarios.
  - **Annual carbon emissions (CO_2e):** South Africa's 2022 emissions were estimated at 436 $MtCO_2e$ (DFFE, 2024).
- **Identify the types of options available:** Three energy scenarios (including sensitivity analysis) were developed for this study based on the following considerations:
  - **Pathway and scenario-specific inputs and assumptions**
    - Policy and regulations, including carbon emissions from electricity, adherence to air quality (AQ) standards, carbon emissions tax (CO_2 tax), Carbon Border Adjustment Mechanism (CBAM), and other export market regulations.
    - Generation, including the coal fleet decommissioning schedule, EAF, CCS viability timeline, and technology learning rates.
    - Fuel prices
    - Capital, including the size of the market and funding, and the cost of capital.
  - **Universal inputs and assumptions**
    - Generation, such as embedded generation (on-site), Commercial & Industrial Private wheeling Gx, grid expansion rate, generation build rate, and technology options (including load shedding and unserved energy)
    - Demand, including the universal access to electricity, the demand and energy forecasts per sector, fuel switching, and EVs.
    - Regional electricity trade via the Southern Africa Power Pool (SAPP)

- **Identify exogenous factors:** Exogenous factors that might influence the magnitude of funding required by 2050 were considered as part of the pathways development process. These included aspects such as: 1) international collaboration and coordination on climate change action, 2) international and local economic conditions, 3) energy demand patterns, 4) climate events, 5) global energy prices, and 6) technology advances that could influence the cost of capital and appetite for investment funding into South Africa's electricity infrastructure. These exogenous factors determine the options available and the range of the required South African carbon budget to 2050.
- **Estimate costs of achieving objectives:** This step was completed in two ways. Firstly, extensive technical energy (electricity generation) and power systems (grid stability) modelling was conducted. This was informed by technical consultation sessions to obtain new capacity build programmes, energy mix, and total capital expenditure (Capex) estimations. Secondly, the modelled results were compared to the ranges identified in a parallel literature review. In addition, a supplementary CGE modelling report will be produced to provide insight into the socio-economic impact stemming from the pathways and scenarios generated in this report.
- **Estimate the funding gap:** A soft market sounding exercise was conducted with market participants, including equity and debt funders of energy infrastructure projects, to estimate the magnitude of available Capex funding within the energy infrastructure sector. The potential funding gap (i.e., capital available vs capital required) to reach the investment required over the forecast period to 2050 was also estimated. A range of funding options that could address the funding gap and their respective mobilization requirements (including financial, policy, institutional, regulatory, or technical aspects) were considered. The funding gap was then estimated based on the outcomes from the soft market sounding exercise, current public and private spending on energy infrastructure, and the technical modelling results for the Capex financing requirement ranges. These findings were compared to the ranges identified in the parallel literature review.
- **Regulatory analysis:** A detailed assessment of the policy and regulatory frameworks that govern the flow of public and private investments in energy infrastructure was conducted. PIR changes were identified that will be required to increase investment in climate-resilient energy infrastructure, with recommendations made based on input from soft market sounding participants, international case studies, and leading practices within the current South African energy landscape.

The research was conducted over a two-year period spanning from June 2023 through June 2025, during which all data collection, analysis, and interpretation were completed.

2.2 Phasing of Workstreams

The methodology was informed by and supported through the following workstreams.

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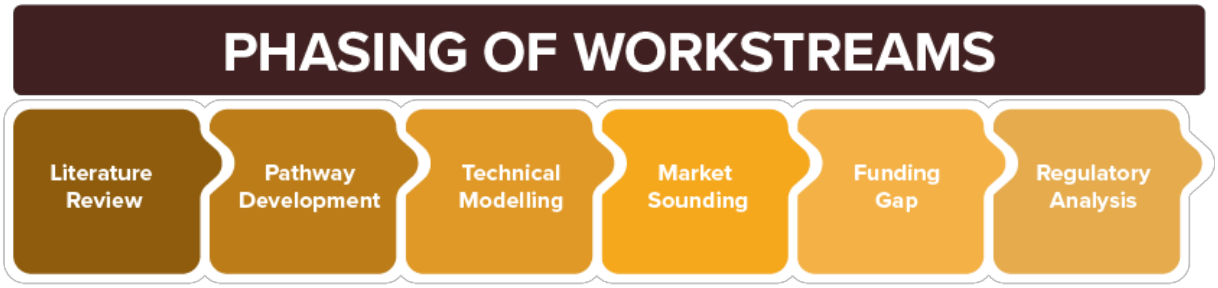


- **Literature review:** This involved sourcing relevant literature and data for review and analysis in support of the adapted 'Beyond the Gap' methodology and addressing the research questions in this report. New, relevant publications were incorporated as they became available or were identified during the study period. While the literature review was compiled in a separate report, the content was utilized throughout this report to either substantiate statements or compare the current findings to previous research identified in the literature review.
- **Pathway development:** This involved framing the technology mix pathways and identifying suitable variable inputs and assumptions to apply in the pathway modelling process to achieve the energy and carbon targets, based on literature and technical inputs. These are presented below as the pathway scenarios. These pathways were formally modelled as technical energy and power system scenarios, which were developed through a consultative process with the project partners, including the evaluation of a range of modelling sensitivities.
- **Infrastructure technical modelling:** this entailed conducting two types of modelling to identify the required generation, transmission, and distribution infrastructure investments for the three scenarios as developed using the pathways' inputs:
- **Energy modelling:** The objective was to identify the least-cost infrastructure pathways to meet the emissions targets.

  Power system modelling: The objective was to understand the current and future transfer limits of the corridors and approximate the required transmission infrastructure dimensions to unlock certain capacities and the associated grid investment cost. The secondary objective was to understand the network compensation requirements of the final scenario, including the additional grid infrastructure costs required to facilitate the high penetration of inverter-based VRE generation and storage. Through technical energy[6] and power systems modelling, these scenarios provide the investment required to achieve the stated targets.

- **Market sounding:** This exercise was conducted with commercial banks, local infrastructure funds, local developmental finance institutions, and IPPs. Participant feedback informed key aspects, including the potential funding gap, obstacles, and enabling factors related to raising or allocating additional funds for energy infrastructure. In addition, potential innovative funding approaches and the levels of market risk the market participants were prepared to take on in relation to off-take mechanisms and the current market structure were investigated.
- **Funding gap calculation:** A funding gap range was estimated across the three scenarios based on the findings from the literature review, outcomes from the soft market sounding exercise, current public and private spending on energy infrastructure, and the financing requirement ranges obtained from the technical modelling performed.
- **Regulatory analysis to understand gaps and produce recommendations:** A detailed assessment of the policy and regulatory frameworks that govern the flow of public and private investments in energy infrastructure was conducted. This included examining the main strengths and weaknesses of the PIR framework currently in place, as it relates to funding energy infrastructure in South Africa. In addition, the analysis considered international best practices regarding energy funding mechanisms to advance renewable energy goals. Based on these inputs, the inputs obtained from the market sounding exercise, and the technical modelling, concrete recommendations are made for regulatory improvement and reform to achieve a competitive, resilient, and sustainable electricity sector by addressing the funding gap.

[6] For the purposes of this report, '"energy"' is defined as electricity, encompassing renewable sources, coal, gas, uranium, and diesel. From an infrastructure perspective, the report deals with electricity generation, storage, transmission, and distribution infrastructure. Upstream infrastructure for the supply of coal, gas and diesel fuels is incorporated in the unitised cost of these energy sources as they are consumed by the associated electricity generation plants i.e., the study does not estimate the capital costs required for upstream infrastructure such as gas pipelines, LNG terminals, petrochemicals manufacturing, and coal mines.

3 Pathways and Scenarios Development

3.1 Local Development Pathways

This section describes the range of high-level pathways that the project team, with inputs and oversight from the Project Steering Committee, envisaged at the inception stage. The three pathways provide the constraints for modelling the associated scenarios. The team has made specific decisions regarding the variable inputs based on the literature, as well as the assumptions and sensitivities to be applied when modelling the three scenarios using each of the three pathways in the technical modelling workstream.

While informed by a wide range of data and information, these pathways are based on South Africa's JET Investment Plan (The Presidency, 2022) and carbon budget between 2010 to 2050 which was originally defined in the National Climate Change Response White Paper (RSA: NCCRP, 2014) and South Africa's Intended Nationally Determined Contribution, which was presented to the UNFCCC (2022).

For each of the three high-level pathways, the associated scenario must identify the energy infrastructure investments required between 2024 and 2050 to achieve:

- **Energy security:** Ensuring a sufficient supply of electricity within the South African electricity system for economic and human development,
- **Affordability:** From a technology, financing (cost of capital), and end-user perspective, and
- **Carbon budget:** In agreement with the long-term temperature goal of the Paris Agreement between 2010 and 2050. The NDCs indicate South Africa's 'fair share' of the remaining GHG emissions allowance.

3.2 Local Development Pathways within the Global Context

The Intergovernmental Panel on Climate Change (IPCC) special report (Masson-Delmotte et al., 2018) focused on the impacts of global warming of 1.5 degrees Celsius above pre-industrial levels, GHG emission pathways, and related strategies to address climate change. While the report does not exclusively revolve around global cooperation, it does emphasise the importance of international collaboration to address the challenges of climate change effectively. The level of collaboration and coordination will directly affect the capital cost to finance green energy infrastructure development, and the ability for countries to manage their collective carbon budgets. Figure 7 illustrates international development pathways with three high-level scenarios across the horizontal:

- **Pathway 1:** Global alignment to keep global warming below 1.5 degrees Celsius in relation to pre-industrial levels as per the Paris Agreement.
- **Pathway 2:** A fragmented world, where only certain countries achieve their NDC targets and warming is limited to below 3 degrees Celsius.

- **Pathway 3:** Business-as-usual, where climate commitments generally stall and fail, with global warming exceeding the 3 degrees Celsius threshold.

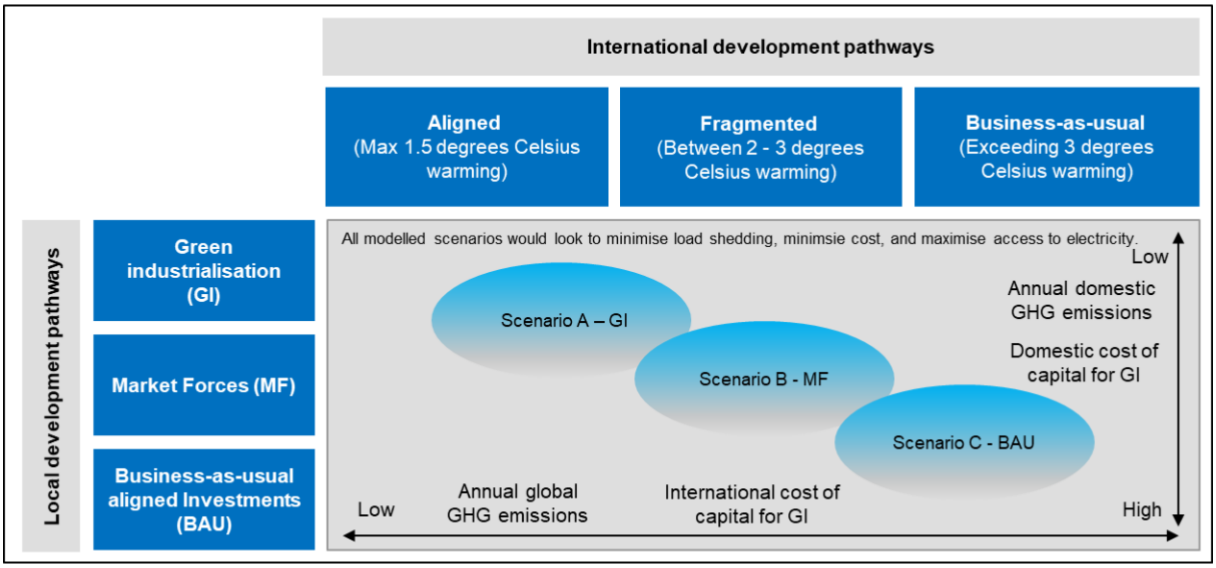


Figure 7: Summary of Scenarios Under the International and Local Development Pathways

Sources: Masson-Delmotte et al. (2018) and JET IP (2022).

The local development pathways across the vertical show South Africa's high-level approach towards meeting its global climate targets expressed in the JET IP. Using Just Energy Transition Partnerships (JETPs) as catalysts, the JET IP aims to address the country's energy crisis as well as the systemic challenges of poverty, inequality, and unemployment by driving energy transition through industrial development, innovation, and economic diversification. Given that the local pathways would need to balance the dynamics of energy security, affordability, and GHG emission limits[7] within the global context, some parameters that will shape the different modelling scenarios are defined. For ease of reference, the three scenarios are named after the local development pathways.

- The **Green Industrialization** pathway assumes that the country is fully aligned and has an environmentally conscious and low-emissions development strategy to curtail global warming, which drives a carbon emissions target of 2 Gt by 2050 for the electricity sector and mandates AQ compliance by 2030. For this pathway, a large market exists for green industrialization finance, and the capital cost is low and accessible for renewable energy technologies. In contrast, the capital cost for fossil fuel technologies attracts a premium. In addition, new

[7] The Just Energy Transition Investment Plan (JET IP) (The Presidency, 2022) is aligned with the updated NDC emissions targets and shows that a net-zero CO_2 goal will be achieved in 2050, and an overall GHG (expressed as CO_2e) emissions budget over the period 2021 to 2050 of 7.8–8.5 $GtCO_2e$. As part of the pathway development, the total contribution allocated to electricity generation proportional to the overall emissions range is estimated to fall within 2 $GtCO_2e$ (the green industrialization pathway) to 3 $GtCO_2e$ range (the market forces pathway).

technology learning rates are optimistic and costs decrease, the competition for fossil fuels is low, resulting in lower coal and gas prices, and the EAF of the existing coal fleet improves.

- The **Market Forces** pathway assumes that the country is mostly aligned with its NDC targets, but that the capital costs and other economic factors influence decisions regarding the country’s energy mix. These could limit South Africa’s ability to adhere strictly to AQ standards and carbon policies. This pathway assumes a carbon emissions target of 3 Gt by 2050 for the electricity sector, and AQ compliance is only mandated by 2035. New technology learning rates, coal and gas prices, and EAF of the existing coal fleet are all middle-of-the-road scenarios.
- The **Business-as-usual** aligned investments pathway involves South Africa abandoning its NDC commitments and compliance with AQ standards due to a breakdown in global alignment or acute economic cost challenges. The pathway retains a focus on electricity production through the least-cost means and the security of supply.

Significantly, the high-level pathway-specific assumptions that underpin the final scenarios are not necessarily unique to each, and these three scenarios are depicted as overlapping in Figure 7.

3.3 Defining the Scenarios to be Modelled

The inputs and assumptions into the model[8] are as follows:

1. Pathway-specific inputs and assumptions: These inputs, decisions, and assumptions are related to the specific scenario to be tested, e.g., adherence to AQ regulations.
2. Universal inputs and assumptions: These are consistent across the scenarios and not directly influenced by the specific scenario, e.g., the development of embedded generation, such as rooftop solar PV.

While some inputs are in the form of constraints or limits, the model may not necessarily reach each of these constraints or limits. For example, in Scenario C, where the decommissioning time frame for existing coal plants is extended, the model will still determine the actual decommissioning time frame based on other constraints, such as carbon budget adherence and minimizing the overall system cost. Therefore, tables 4 and 5 set out the conceptual framework of non-exhaustive, high-level inputs and assumptions across the three scenarios.

[8] *The energy modelling is carried out using the Open-Source Energy Modelling System (OSeMOSYS) software. See Section 4.1.2 Methodology for a more detailed description.*

Table 4: Local Industrialization-Oriented Pathway Assumptions per Scenario

Area	Model parameter or descriptor	Scenario A Green Industrialization	Scenario B Market Forces	Scenario C Business-as-usual
Policy and regulations	Carbon emissions from the electricity sector	2.0 $GtCO_2e$	3.0 $GtCO_2e$	No limit
	Adherence to air quality (AQ) standards	Mandated by 2030	Mandated by 2035	Not mandated
	Carbon Border Adjustment Mechanism (CBAM) and other export market regulations[9]	Fully aligned, high impact on export market	Partial alignment (global disconnect), though reduced, export market stays largely intact	Partial alignment (local and global disconnect), current export markets stay intact
	Carbon emissions tax (CO_2 tax)	As per Draft IRP 2023 2026: USD 16, 2030: USD 25, 2040: USD 50, 2050: USD 100	As per Draft IRP 2023 2026: USD 16, 2030: USD 25, 2040: USD 50, 2050: USD 100	Reduced 2026: USD 16, 2030: USD 25 2040: USD 45, 2050: USD 66
Generation	Coal fleet decommissioning	Pathway 1 (IRP 2019, with adjustments) (University of Pretoria General Equilibrium Model (UPGEM), December 2023)	Pathway 1 (IRP 2019, with adjustments) (UPGEM, December 2023)	Pathway 2 (Delayed decommissioning timeline relative to pathway 1) (UPGEM, December 2023)

[9] *Descriptor of the external environment, as opposed to a modelling input.*

Area	Model parameter or descriptor	Scenario A Green Industrialization	Scenario B Market Forces	Scenario C Business-as-usual
	Coal fleet EAF[10]	High 65% from 2023 to 70% by 2035 until end, except Medupi and Kusile which are 73% from 2025	Medium 65% throughout, excluding Medupi and Kusile, which are 73% from 2025	Low 60% throughout, excluding Medupi and Kusile, which are 73% from 2025
	Carbon capture and storage (CCS)	Option for coal power plants from 2035	Option for coal power plants from 2040	Option for coal power plants from 2040
	Technology costs and learning rates	Optimistic Likely scenario from Review of the IRP 2023 (Meridian Economics, 2024)	Moderate Base Case scenario from Review of the IRP 2023 (Meridian Economics, 2024)	Pessimistic Stress scenario from Review of the IRP 2023 (Meridian Economics, 2024)
Fuel Prices	Coal and natural gas	Low Net Zero Emissions by 2050 Scenario (NZE) from International Energy Agency (IEA) World Energy Outlook (WEO) (2024)	Moderate Announced Pledges Scenario (APS) from IEA WEO (2024)	High Stated Policies Scenario (STEPS) from IEA WEO (2024)

[10] *EAF is highest under the Green Industrialization scenario A because older and underperforming coal plants will be decommissioned, which improves the overall EAF of the remaining coal fleet. Conversely, under the Business-as-usual scenario, the coal fleet decommissioning is delayed, which will negatively affect the overall EAF.*

Area	Model parameter or descriptor	Scenario A Green Industrialization	Scenario B Market Forces	Scenario C Business-as-usual
Capital	Size of market and funding[11]	Significant local and international funding available for zero-carbon generation options. Little to no finance for carbon-intensive generation (but more available for gas vs coal).	Local and international funding available for zero-carbon generation options. Finance for carbon-intensive generation is more expensive.	Limited local and international funding available for zero-carbon generation options. Finance for carbon-intensive generation is even more expensive.
	Cost of capital	10% Capex premium added to new fossil fuel technologies (as a proxy for higher cost of capital)	5% Capex premium added to new fossil fuel technologies (as a proxy for higher cost of capital)	Cost of capital is equal for new renewable energy and new fossil fuel technologies

[11] *Descriptor of the external environment, as opposed to a modelling input.*

Table 5: Universal Inputs and Assumptions Across the Three Local Pathways

Area	Model parameter or descriptor	Assumption
Generation	Embedded generation (on-site)	Quantum of embedded generation for 2024 was based on Eskom weekly system status report, with nominal growth rate as shown in Section 4.3.4.
	Commercial & Industrial Private wheeling Gx	Existing, committed, and planned generation capacities for private sector projects were obtained from the Generation Connection Capacity Assessment (GCCA) 2025.
	Grid expansion rate and generation build rate	No constraints were applied in terms of maximum grid expansion or generation build rates.
	Technology options	Refer to Section 4.3.5
Demand		Data from the University of Cape Town: Energy Systems Research Group (UCT: ESRG) demand forecast model was adopted. Further discussion on this is provided in Section 4.3.2.
Regional electricity trade (SAPP)		Cahora Bassa electricity contribution included but ends in 2030. Mozal smelter load modelled as internal to South Africa. No other cross-border electricity flows were incorporated.
Load shedding		Load shedding was enabled as a technology option, i.e., the model deploys load shedding if no other technology options can meet the demand (e.g., due to model constraints).

Section B: Methods, Analyses, Results, Findings, Discussion, and Conclusions

4 Infrastructure Technical Modelling and Sensitivity Analyses

4.1 Introduction

The overall objective of the infrastructure technical modelling was to identify the least-life-cycle-cost electricity generation mix and the transmission infrastructure that meets the specified constraints (e.g., least cost, energy for all, CO_2 budget, and electricity demand) over the projected timeframes (2030, 2040, and 2050). The pathways define the scenarios and the associated parameters and constraints to be modelled.

For the period up to 2030, a steady state power system analysis was used to quantify the transmission constraints. Beyond 2030, the energy model overlooks the transmission corridor constraints by adopting a 'copper plate' approach and optimizes for generation only. The resultant energy flows from the model enable the identification of the transmission corridors required to unlock and ensure affordable electricity and security of supply. Corridor planning was developed in a spatial environment using Geographic Information System (GIS) software to quantify the extent of the transmission expansion projects.

The technologies and fuels identified as significant by the energy model will be used as inputs to the supplementary CGE model report to examine their respective impacts on society and the economy.

4.2 Methodology

4.2.1 Open-Source Energy Modelling System (OSeMOSYS)

Open-Source Energy Modelling System (OSeMOSYS) is a tool designed to focus on detailed power representations, or multi-resource modelling, including material and financial resources, and all energy systems. It was developed in collaboration with a range of institutions, including the International Atomic Energy Agency (IAEA), the United Nations Industrial Development Organization (UNIDO), KTH Royal Institute of Technology, Stanford University, University College London, University of Cape Town (UCT), Paul Scherrer Institute, Stockholm Environment Institute, and North Carolina State University. The original working code of OSeMOSYS was first introduced in 2008 in a presentation at the International Energy Workshop in Paris.

OSeMOSYS uses generation capacity and energy delivery to calculate the energy supply mix that meets the energy service demands annually and at every time step of the case being studied, while minimizing the total discounted costs. It can compute the energy supply mix for individual energy sectors, including heat, electricity, and transport, or the sum of these sectors. These energy demands can be addressed through a range of technologies that possess specific techno-economic characteristics and utilize a set of resources defined by their respective potentials and costs. Policy and project scenarios may impose technical constraints, economic realities, or environmental targets. As with most long-term optimization modelling tools, OSeMOSYS assumes a unique decision-maker, perfect foresight, and competitive markets (Howells et al., 2011).

Results from OSeMOSYS include new power generation capacity building, existing and new power generation costs, renewable energy penetration, as well as sensitivity analyses that assess how changes in input parameters, such as electricity pricing assumptions, influence the overall energy system and the success of procurement and optimization strategies.

4.2.2 Model Management Infrastructure (MoManI)

OSeMOSYS has various user interfaces, including ClickSAND, the Low Emissions Analysis Platform (LEAP), and the Model Management Infrastructure (MoManI). MoManI, an open-source interface with both online and standalone versions, was adopted for this assignment due to its flexibility and superior user interface compared to other interfaces.

4.2.3 FlexTool

FlexTool is a tool developed by the International Renewable Energy Agency (IRENA) in collaboration with the VTT Technical Research Centre of Finland to perform power system flexibility assessments based on national capacity investment plans and forecasts. By simulating and optimising the dispatch of electricity generation, FlexTool helps identify flexibility options and assess them, including energy storage, demand response, and flexible generation technologies. It operates across various timescales, ranging from short-term operational decisions to long-term planning, to understand the reliability, efficiency, and resilience of power systems in the context of fluctuating supply and demand.

After OSeMOSYS determined the optimal new capacity build based on cost and other constraints, FlexTool was used to check the suitability and, when required, refine the proposed capacities by analysing the hourly dispatch. This ensured the real-world practicality of the merit order dispatch for system operators and the inherent ramping constraints on other technologies.

4.2.4 Energy Model Configuration

The energy model flow logic is graphically represented in Figure 8 with a reference energy system (RES) diagram. The RES diagram illustrates the primary energy sources assumed in the model (including fossil fuels and renewable energy resources); all the generation technology options (existing, planned, and potential options); the energy storage technology options; the existing transmission interconnectors, transmission, and distribution (i.e., renewables collector networks) systems; the supply area load; rooftop PV; unserved energy; and the energy flows between these.

Note that the RES is illustrated at a provincial level and serves as a high-level view of the building blocks that represent the entire South African electricity system (see Figure 6). A higher resolution version of the RES diagram is provided in Annexure A: Reference Energy System (RES) Diagram.

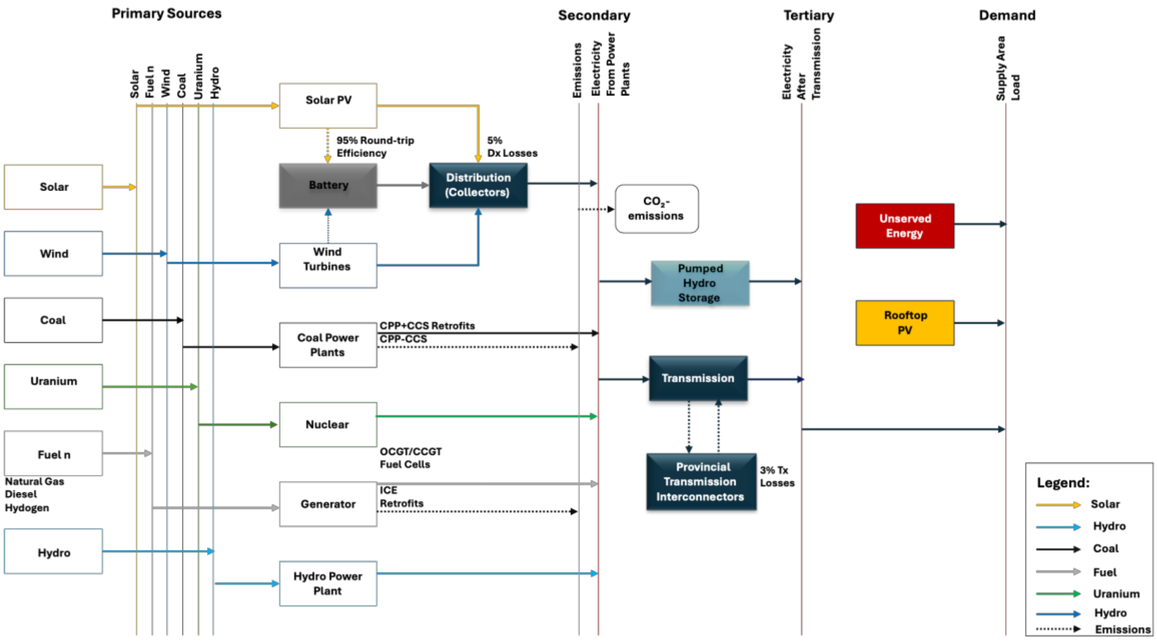


Figure 8: Reference Energy System (RES) diagram

4.3 Assumptions and Limitations

4.3.1 General

The following general assumptions were applied across all model scenarios:

- The model currency is USD. Any input costs that were in ZAR were converted to USD at an exchange rate of 18.80 ZAR/USD.
- All future monetary values in the model are in 2024 real terms; therefore, inflation and escalation have been excluded. The only costs that change over time are the gradually reducing costs of solar, wind, battery energy storage, and carbon capture and storage (CCS), due to technology learning rates.
- The model assumes a discount rate of 8% to 2024 real terms, as per the Draft IRP (2023) and the Review of the IRP 2023 (Meridian Economics, 2024).
- Two types of typical day were modelled, a summer weekday and a winter weekday. Each typical day consists of 24 one-hour intervals.
- The model assumed a reserve margin of 15%.
- The ten-node model has one node per Eskom supply area.
- The modelling period is 28 years (2023 to 2050).

- The model calculates for discrete annual and five-year intervals:
    - 2023 (annual)
    - 2024 (annual)
    - 2025 (annual)
    - 2030 (five-year block representing 2026 to 2030, inclusive)
    - 2035 (five-year block representing 2031 to 2035, inclusive)
    - 2040 (five-year block representing 2036 to 2040, inclusive)
    - 2045 (five-year block representing 2041 to 2045, inclusive)
    - 2050 (five-year block representing 2046 to 2050, inclusive)

4.3.2 Demand

Electricity demand was based on data obtained from the Single Node Hourly Demand Model (herein referred to as the 'demand forecast') developed by the University of Cape Town: Energy Systems Research Group (Merven, 2023). The demand forecast was used to obtain hourly demand profiles and estimate total national annual electricity consumption up to 2050. The demand forecast includes several scenarios to choose from. The following scenario options were selected within the demand forecast:

- Demand Scenario: Reference,
- Distributed PV Scenario: Distributed PV Excluded, and
- Other Onsite Setting: Excluded.

The electricity demand from electric vehicles (EVs) is included in the demand forecast. The EV electricity demand as a portion of total national electricity demand per year from the reference demand scenario is shown in Figure 9.

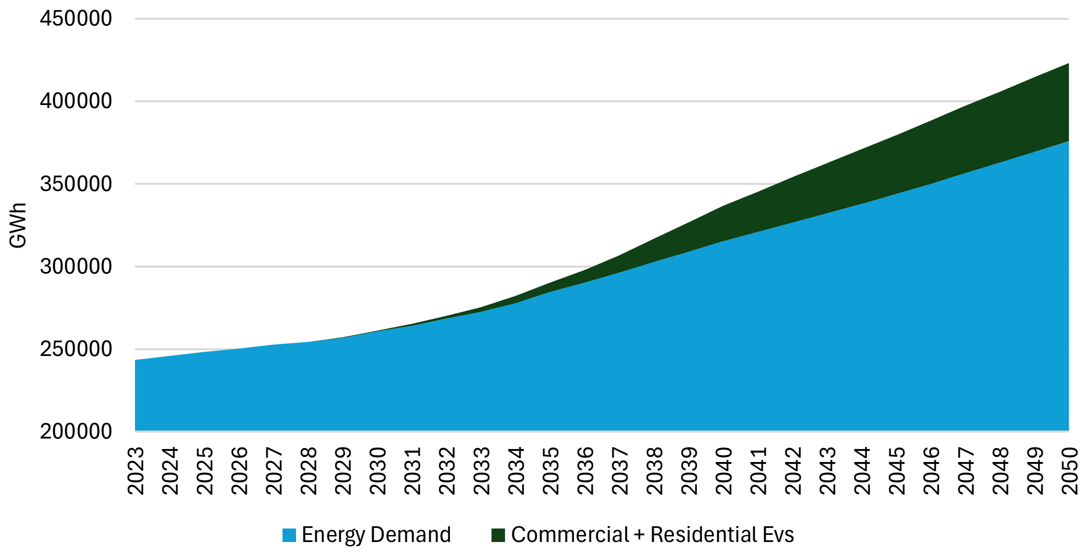


Figure 9: Electric Vehicles (EVs) Demand as a Portion of Total Demand

Source: ESRG Single Node Hourly Demand Model (Merven, 2023).

Electricity demand to produce green hydrogen is not included in the demand forecast. No reliable data for this projection was identified at the time of this study, and it was therefore not included in the current energy model.

Scenarios addressing significant changes in Sasol's electricity demand because of future business model changes, such as changes in product portfolio, scaling down, or shutting down, are not included in the demand forecast. While the project team was able to consult with Sasol during the study, the information provided regarding its future was extremely wide-ranging. In the demand forecast, industrial demand is assumed to have a limited level of energy-efficiency improvements and fuel switching, with demand primarily driven by economic growth.

The Mozal smelter load (in Mozambique) is included in the demand forecast and the energy model as part of the South African load, as opposed to a separate, cross-border load.

Rooftop PV systems were included in the demand forecast; however, this was removed from the demand included in the energy model and was instead modelled as a separate generator (see Section 4.3.4).

Eskom's TDP in 2023 was used to apportion the national demand per Eskom supply area. Note that the TDP includes ten supply areas, with one per province and one additional for the Hydra Central area between the Northern, Western, and Eastern Cape, Free State, and Lesotho. However, the demand for Hydra Central was set to zero as this area is primarily an entry point for new power generation capacity into the grid and not considered a consumer or demand area.

Figure 10 and Figure 11 illustrate the hourly demand profile and energy demand per supply area, respectively.

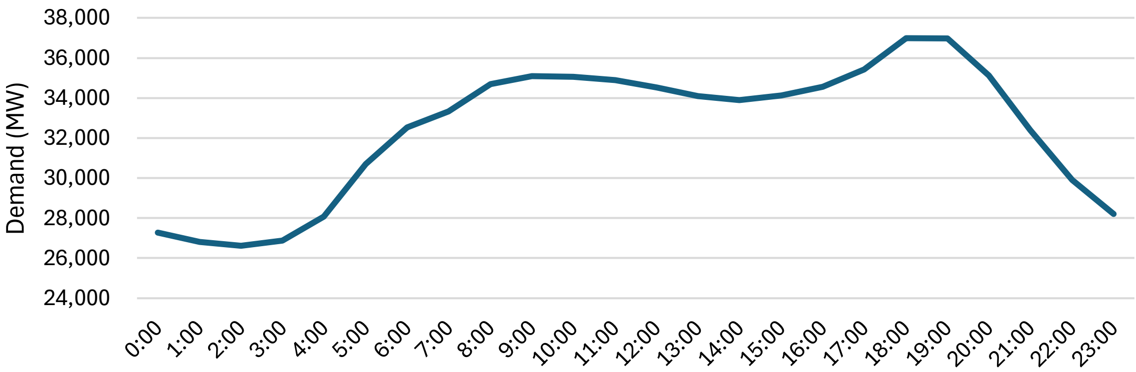


Figure 10: National Demand Profile

Source: ESRG Single Node Hourly Demand Model (Merven, 2023).

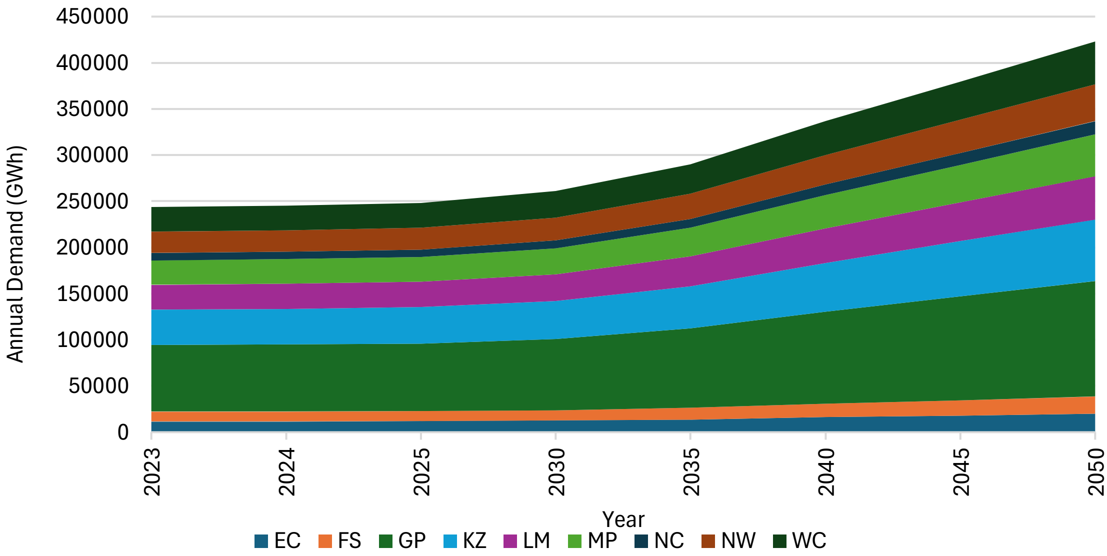


Figure 11: Energy Demand Per Supply Area

Source: ESRG Single Node Hourly Demand Model (Merven, 2023).

4.3.3 Eskom Generation

All Eskom generators and coal plants were individually modelled with distinct installed capacities obtained from various sources including the University of Pretoria General Equilibrium Model (UPGEM) (Horridge et al., 2024), which is a CGE model specifically designed to analyse the South African economy, and Eskom reports, except for small hydro power plants which were modelled as a single technology due to their small capacities relative to other existing technologies.

A fleet-level average EAF of 65% was calculated using data published by Eskom for its power plants between 2022 and 2023. The EAF percentage for the Eskom power plants was adjusted for each scenario:

- Scenario A (high): 65% from 2023 to 70% by 2035, 70% to 2050, excluding Medupi and Kusile, which are 73% from 2025,
- Scenario B (moderate): 65% throughout, excluding Medupi and Kusile, which are 73% from 2025, and
- Scenario C (low): 60% throughout, excluding Medupi and Kusile, which are 73% from 2025.

Plant-level efficiency data for the Eskom coal fleet is not readily available to the public. To address this challenge, the model assigns plant efficiency values based on the established average efficiency ranges associated with the different power generation technologies used at each plant (e.g., coal, open cycle gas turbines (OCGTs), and nuclear).

Decommissioning pathways for the Eskom coal fleet were obtained from the UPGEM model (Horridge et al., 2024). The decommissioning timelines in the UPGEM model were initially based on the IRP2019 with adjustments made based on public announcements, the Draft IRP2023 and discussions with PCC and other stakeholders. The decommissioning timelines were last updated in December 2023. The dataset contains three distinct decommissioning pathways for the Eskom coal fleet:

- Pathway 1: Based on the IRP 2019, with adjustments,
- Pathway 2: Delayed decommissioning timeline relative to Pathway 1, and
- Pathway 3: Faster decommissioning timeline relative to Pathway 1.

Pathway 1, which is based on the benchmark electricity generation-mix projection scenario for IRP 2019 with minor adjustments for known delays and grid constraints, was adopted for scenarios A and B. Pathway 2 was adopted for Scenario C. Figure 12 depicts pathways 1, 2, and 3.

The decommissioning pathways are applied as deadlines per power plant within the energy model. The energy model is allowed to dispatch a power plant up until its specified deadline and may stop dispatching a power plant before its deadline to meet carbon emissions constraints or adopt lower-cost alternatives.

There is no lump sum decommissioning cost applied when a power plant ceases to be dispatched by the energy model; however, fixed operation and maintenance (FOM) costs are still applied in the model even after a power plant is no longer dispatched. This ongoing cost represents a care and maintenance approach, which includes maintaining the power plant in a reasonable condition as insurance for unforeseen risks to supply security.

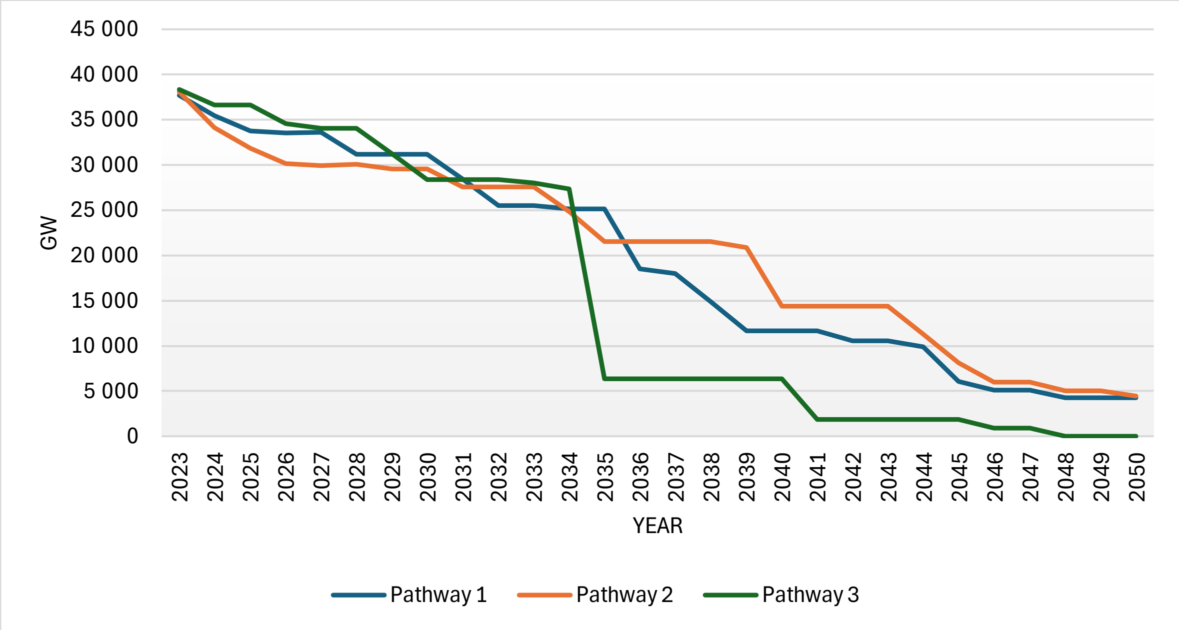


Figure 12: Eskom Coal Fleet Decommissioning Pathways

Source: Input Dataset from University of Pretoria General Equilibrium Model (UPGEM) (Horridge et al., 2024).

4.3.4 Other Existing and Committed Generation

The Renewable Energy Independent Power Producers Procurement (REIPPP) Programme Bid Windows 1 to 6 data in South Africa provided the foundation for the assumptions made regarding existing, committed, and planned generation capacities for renewable energy (wind and solar) projects (DMRE, 2023a). The following assumptions regarding the projects' commercial operation dates (COD) were made:

- Operational projects: 9 GW online from the start of the model time horizon in 2023,
- Projects under construction: 17 GW online from 2025, and
- Projects which have not yet achieved Financial Close: 30 GW online from 2027.

For the capacity factors of the renewable energy projects, see Section 4.3.10.

Based on the Energy Storage Independent Power Producer Procurement Programme (ESIPPPP) Rounds 1 to 3, and the Eskom BESS programme, the model assumed a total of 2 100 MW of BESS capacity would be online before 2030. Based on the Gas Independent Power Producer Procurement

Programme (GIPPPP) Round 1 and 2, the model also assumed a total of 3 000 MW of new gas capacity would come online before 2030 (DMRE, 2023a).

The Generation Connection Capacity Assessment (GCCA) 2025, published by Eskom, was used to obtain the existing, committed, and planned generation capacities for other private sector projects (not procured through the IPP Office) per technology per supply area, with the same commercial operation date assumptions as noted above.

The Avon and Dedisa open-cycle gas turbine power plants are captured in the model as additional private sector generation projects.

The model assumes that the energy procurement contract between South Africa and Mozambique regarding the Cahora Bassa hydro power plant will end in 2030.

4.3.5 Rooftop Photovoltaic (PV) Systems

Rooftop PV systems were modelled as a stand-alone technology supplying the load directly (i.e., generating power at the point of consumption) as shown in Figure 8. This approach minimises transmission losses and demand on the main grid. Eskom’s weekly system status reports were used to quantify the current capacity of rooftop solar PV.

A nominal growth rate assumption was applied to the current capacity level of rooftop solar PV, as agreed with the Project Steering Committee during technical workshops.

Figure 13 shows the quantity of existing and forecasted rooftop PV capacity in GW per supply area per year. Hydra Central is not included in the figure since it is assumed to have negligible demand and therefore no need for rooftop solar PV.

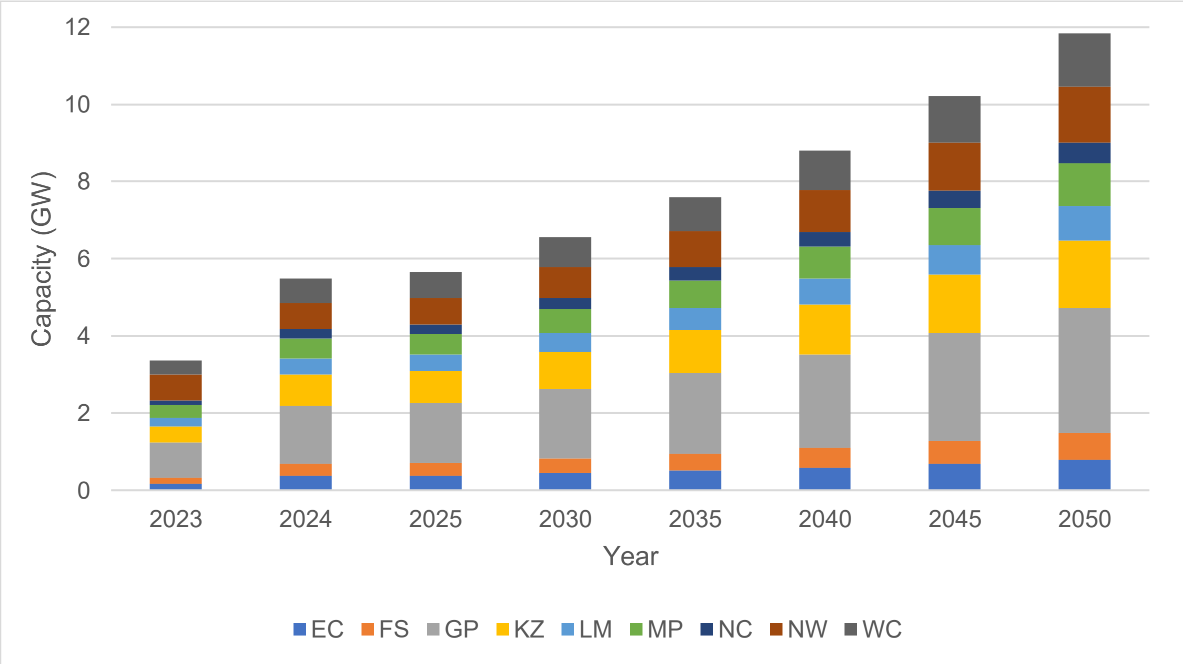


Figure 13: Rooftop PV Capacity Forecast

Source: Input Dataset from University of Pretoria General Equilibrium Model (UPGEM) (Horridge et al., 2024).

4.3.6 Fuel Prices

Fuel prices for diesel and uranium were obtained from the Review of the IRP 2023 (Meridian Economics, 2024), with no escalation applied during the modelling period. While diesel is included in the model, it is only used as a fuel for Eskom gas turbines.

Natural gas and coal prices were obtained from the IEA World Energy Outlook (WEO) 2024, and the price changes over time were modelled according to these forecasts. In this study, Scenario A aligns well with the Net Zero Emissions by 2050 (NZE) scenario in the IEA WEO, Scenario B aligns well with the APS scenario, and Scenario C aligns well with the STEPS scenario.

Fuel prices for each scenario are shown in Table 6.

Table 6: Fuel Prices (USD/GJ)

Fuel Type	Scenario A	Scenario B	Scenario C
Natural Gas	2023: 11.56 2030: 4.55 2040: 4.33 2050: 4.30	2023: 11.56 2030: 6.22 2040: 5.53 2050: 4.86	2023: 11.56 2030: 6.95 2040: 7.77 2050: 7.80
Coal	2023: 6.29 2030: 2.60 2040: 2.08 2050: 1.90	2023: 6.29 2030: 3.10 2040: 2.55 2050: 2.36	2023: 6.29 2030: 3.80 2040: 3.38 2050: 3.17
Diesel	2023–2050: 45.33	2023–2050: 45.33	2023–2050: 45.33
Uranium	2023–2050: 1.00	2023–2050: 1.00	2023–2050: 1.00

4.3.7 Carbon Capture and Storage (CCS) Retrofits

The total cost of CCS consists of the cost of capturing, transporting, and storing the carbon.

The Capex and fixed and variable Opex values for the carbon capture plant have been sourced from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) dataset (NREL, 2024). The selected case was the moderate scenario involving the "retrofit of unabated Sub-Critical pulverized coal plant with commercially available solvent-based post combustion carbon capture (PCCC) designed for 95% capture" (NREL, 2024).

Retrofitting an existing coal plant with CCS also reduces the net power output due to the large parasitic steam and power loads required for appreciable levels of carbon capture. Net power output penalty and efficiency penalty were also sourced from the moderate scenario within the NREL ATB dataset. A summary of the Capex, Opex, and performance penalty parameters for carbon capture retrofits is provided in Table 7.

Table 7: CCS Retrofit Costs and Performance Penalties

Parameter	2035	2040	2045	2050
Capex (USD/kW)	1 747	1 651	1 555	1 459
Variable Opex (USD/MWh)	16.53	16.29	16.04	15.79
Fixed Opex (USD/kW)	147	142	136	131
Net energy output penalty (∆% from pre-retrofit)	–22%	–22%	–22%	–22%
Efficiency penalty (∆% from pre-retrofit)	29%	29%	29%	29%

Captured carbon can be transported by various methods, typically by pipeline, rail, and truck. Trucks are the most economical for smaller quantities and distances of up to 200 km. Pipelines and rail are more economical for greater quantities and larger distances. Mahler and Arndt (2024) report prices for various transportation options and distances involved for carbon in the South African context. For distances of 200 to 750 km, transporting carbon via pipeline is the most practical option. Onshore pipelines cost 1.7 to 6.1 USD/ton CO_2, and offshore pipelines cost 3.8 to 32.4 USD/ton CO_2.

Kearns et al. (2021) have presented a range of values for CO_2 storage based on the US Gulf Coast, with the cost of storage dependent on the selected site and technology. The price range for geological storage is from 2 to 20 USD/ton CO_2, with onshore geological sites being more affordable than offshore geological sites.

Table 8 shows the costs for the transport and storage of carbon for both onshore and offshore options.

Table 8: Cost Range for Carbon Transport and Storage

Mode of Transport	Transport (USD/ton CO_2)	Storage (USD/ton CO_2)	Total Cost (USD/ton CO_2)
Onshore Pipeline	1.7 to 6.1	2 to 20	3.7 to 26.1
Offshore Pipeline	3.8 to 32.4		5.8 to 52.4

Noting the large uncertainty in storage costs, a cost of 30 USD/ton CO_2 was selected for the model. This represents a high cost for onshore pipelines and a mid-range cost for offshore pipelines.

The model has the option for existing coal plants to be retrofitted with CCS from a specific year, according to the scenario:

- Scenario A: 2035,
- Scenario B: 2040, and
- Scenario C: 2040.

The model selects whether the plant will be retrofitted, based on least-cost optimization and emissions constraints.

By July 2024, approximately 50 commercial CCS facilities were operational around the world, with a combined capacity of 51 Mt/a CO_2. There are 45 projects under construction with a combined capacity of 51 Mt/a CO_2, and another 247 projects are at an advanced stage of development with a combined capacity of 180 Mt/a CO_2. Carbon capture capacity has grown at an annual compound rate of 32% since 2017 (Global CCS Institute, 2024).

The Petrobras Santos Basin Pre-Salt Oil Field CCS is the largest operational CCS facility in the world, with a capacity of 10.6 Mt/a CO_2. Carbon dioxide is used to enhance oil recovery in the Pre-Salt Oil Field (Global CCS Institute, 2024). The Drax BECCS (Bioenergy Carbon Capture and Storage) project is a large power generation CCS in advanced development. The Drax BECCS is expected to capture 8 Mt/a CO_2 and sequester the carbon in a saline formation after two of the 660 MW units are retrofitted for CCS (Baringa Partners LLP, 2024).

Medupi and Kusile are each expected to produce 23 to 30 Mt/a CO_2 at a 70% capacity factor. The average size for the currently operational plants is around 1 Mt/a CO_2; thus, the CCS facilities for these two power plants will be far greater than the current operational plants.

While this report does not reference CSIR's work on carbon capture and storage (CCS), which focuses primarily on sequestration potential rather than scale, cost, and performance, this study examines the global state of CCS technology. It then compares the international scale of CCS technology to what would be required for Medupi and Kusile. Although the project team is aware of South Africa's current CoalCO_2-X pilot initiative supported by the Department of Science and Innovation under its Hydrogen Society Roadmap, this was excluded as it was not considered directly relevant to the analysis of CCS technology adoption costs, performance, and scale requirements for 2035/2040. This topic will require more research as this technology continues to develop.

4.3.8 New Technology Options

The following new power generation technology options were defined within the energy model:

- Natural gas fuelled combined cycle gas turbine (NG-CCGT),
- Natural gas fuelled open cycle gas turbine (NG-OCGT),
- Natural gas fuelled internal combustion engine (NG-ICE),
- Nuclear power plant,
- Coal-fired power plant with carbon capture and storage (COAL-CCS),
- Solar PV, and
- Wind turbines.

The following new energy storage technology options were defined within the energy model:

- Pumped hydro storage (PHS), and
- Lithium-ion BESS.

Not all technologies are practical to construct in all supply areas, as they rely on factors such as proximity to natural gas infrastructure, coal resources, and water. Table 9 shows the new power generation and storage technology options that were enabled for each supply area.

Table 9: Locations for New Build Technology Options

New Technology Options	EC	WC	NC	HC	KZN	MP	GP	LM	NW
NG-CCGT	x	x			x	x	x		
NG-OCGT	x	x			x	x	x		
NG-ICE	x	x			x	x	x		
NUCLEAR	x	x			x				
COAL-CCS						x		x	
PHS								x	
SOLAR PV	x	x	x	x	x	x	x	x	x
WIND	x	x	x	x	x	x	x	x	x
BESS	x	x	x	x	X	x	x	x	x

The energy model was configured to enable the commissioning of new power generation and storage technologies from 2030 and beyond, excluding hydrogen-fuelled OCGTs and nuclear power plants to account for technology availability and construction timeframes, respectively. Prior to 2030, only the committed generation projects (see Section 4.3.4) were incorporated into the model. The following assumptions were made for nuclear power plants and hydrogen-fuelled OCGTs, based on research and considering project development and construction timeframes:

- Nuclear: Available from 2040 to 2050, and
- Hydrogen OCGT: Available from 2045 to 2050.

Technology costs, efficiencies, and lifetimes were derived by comparing various data sources, including:

- National Renewable Energy Laboratory (NREL),
- Electric Power Research Institute (EPRI), and
- Meridian Economics.

Table 10 outlines the capital costs (funds or total overnight costs to acquire or build a plant), FOM costs (associated with regular, ongoing maintenance and operation, irrespective of its activity), variable operation and maintenance (VOM) costs (associated with operation of plant based on its activity), fuel costs (where applicable), plant efficiency or capacity factor, CO_2 emissions factor, and project lifetime, assumed per technology within the energy model.

The CO_2 emissions associated with each fuel type were obtained from the IEA database. While CO_2 emissions are associated with the manufacturing, construction, and decommissioning of power plants, this was excluded from the model to focus on the more significant CO_2 emissions associated with operation and fuel consumption. The result is that Table 10 reflects zero CO_2 emissions for nuclear, which is not true in practice, given the high CO_2 content of the built structures and decommissioning processes associated with nuclear power plants.

Table 10: Technology Cost and Performance Parameters

Technology	Year	Capital Cost (USD/kW)	FOM (USD/kW/year)	VOM (USD/MWh)	Efficiency or Capacity Factor[12] (%)	CO_2 Emissions (tCO_2/MWh)	Lifetime (years)
NG-CCGT	2023–2050	886	2	14	50 / 55	0.46	30[13]
NG-OCGT	2023–2050	677	3	14	35 / 44	0.65	
NG-ICE	2023–2050	1 785	16	14	40 / 90	0.57	
Nuclear	2023–2050	6 434	91	9	30 / 95	-[14]	
COAL-CCS	2023–2050	3 830	116	25	23 / 70	-	
PHS	2023–2050	1 396	18	-	40 / -	-	
Solar PV	2023	940	19	-	- / 27 to 34	-	25
	2025	940	19				

[12] Capacity factors shown here are an upper limit. The energy model dispatches according to least cost, without exceeding the capacity factor.
[13] Note that the lifetime of some technologies such as nuclear and PHS are longer than 30 years, however since the model time horizon is only 25 years (2025 to 2050), any lifetime beyond 25 years has no impact on the decision-making of the model.
[14] Nuclear is reflected as zero carbon because the CO_2 emissions involved in construction and decommissioning are excluded from the calculation for all technologies. If included the CO_2 emissions per kWh for nuclear is approximately 12 g, which is like wind and lower than solar (IPCC, 2014). That said, this assessment excludes the threat of toxic waste which is a threat that is not applicable to the other technologies.

Technology	Year	Capital Cost (USD/kW)	FOM (USD/kW/year)	VOM (USD/MWh)	Efficiency or Capacity Factor[12] (%)	CO_2 Emissions (tCO_2/MWh)	Lifetime (years)
	2030	A: 652 B: 759 C: 871	A: 13 B: 15 C: 17				
	2040	A: 613 B: 632 C: 871	A: 12 B: 13 C: 17				
	2050	A: 573 B: 573 C: 871	A: 11 B: 11 C: 17				
Wind	2023	1 378	28	-	- / 24 to 38	-	25
	2025	1 378	28				
	2030	A: 1 131 B: 1 273 C: 1 640	A: 23 B: 25 C: 33				
	2040	A: 1 115 B: 1 187 C: 1 640	A: 22 B: 24 C: 33				
	2050	A: 1 100 B: 1 100 C: 1 640	A: 22 B: 22 C: 33				
BESS	2023	2 225	67	-	95 / - (Round-trip Efficiency)	-	15
	2025	2 225	67				
	2030	A: 1 184 B: 1 499 C: 1 853	A: 36 B: 45 C: 56				
	2040	A: 907 B: 1 147 C: 1 538	A: 27 B: 34 C: 46				
	2050	A: 802 B: 1 015 C: 1 406	A: 24 B: 30 C: 42				

4.3.9 Air Quality (AQ) Compliance Retrofits

Existing coal plants and new builds, which will continue operating after 31 March 2030, are required to adhere to the minimum emission standards (MES) contained in Gazette No. 42013 (Republic of South

Africa, 2018). For plants being decommissioned before 31 March 2030, a once-off suspension can be applied. Table 11 shows the limits applicable to coal plants.

Table 11: Solid Fuel Combustion Minimum Emission Standards (MES)

Common Name	Chemical Symbol	Plant Status	Mg/Nm^{3}*
Particulate Matter	N/A	New	50
		Existing	100
Sulphur Dioxide	SO_2	New	500
		Existing	3 500
Oxides of Nitrogen	NO_x expressed as NO_2	New	750
		Existing	1 100

**Under normal conditions of 10% O_2, 273 Kelvin and 101.3 kPa*

Flue gas filtration, such as fabric filtration, is used in power stations to reduce the particulate matter to below emission limits. Flue gas desulfurization (FGD), which is a costly retrofit, is often employed to reduce the sulphur dioxide emissions. Nitrogen oxides are often controlled by combustion optimization and controlling excess air.

There is limited publicly available information regarding the cost of AQ retrofits for the Eskom coal fleet. However, Eskom has reported that the cost of its coal fleet meeting full compliance with the MES is estimated at over R300 billion. This R300 billion was divided by the total coal fleet capacity to give an approximate ZAR/MW rate, which was then applied to each coal plant based on its individual MW capacity.

The model contains the option for existing coal plants to be retrofitted with AQ equipment from a specific year, according to the scenario:

- Scenario A: 2035,
- Scenario B: 2035, and
- Scenario C: Not mandated.

The model contains the option to spend the retrofit Capex, continue dispatching, or cease dispatching.

4.3.10 Wind and Solar PV Capacity Factors

Capacity factors and production profiles for wind and solar PV technologies were derived for each supply area, based on the actual wind and solar resource historically measured within the respective supply area.

Five reference projects for each technology (solar PV and wind) were selected within each supply area. Five years of historical hourly production data (from 2019 to 2023) was obtained for each reference project using a combination of open-source datasets and the OEG internal projects database. Thus, combining real-world historical production data and theoretically derived production data based on historical weather measurements. The production data for each supply area was aggregated at an hourly resolution to provide a total hourly production profile for each supply area. Probability distribution curves were plotted for each technology in each supply area. Summer and winter days, which represented P50 and P90 production levels, respectively, were selected from these curves.

Table 12 shows the resultant P50 wind and solar PV capacity factors per supply area.

Table 12: P50 Solar and Wind Capacity Factors

Supply Area	Solar Capacity Factor		Wind Capacity Factor	
	Summer	Winter	Summer	Winter
EC	31%	26%	34%	38%
FS	29%	28%	33%	29%
GP	29%	28%	26%	31%
HC	33%	26%	38%	38%
KZN	27%	28%	37%	37%
LM	27%	28%	25%	19%
MP	27%	28%	30%	35%
NC	33%	26%	38%	38%
NW	29%	28%	33%	24%
WC	33%	22%	33%	33%

Figure 14 and Figure 15 below illustrate the P50 summer day profiles for wind and solar PV using the Free State (FS) as an example.

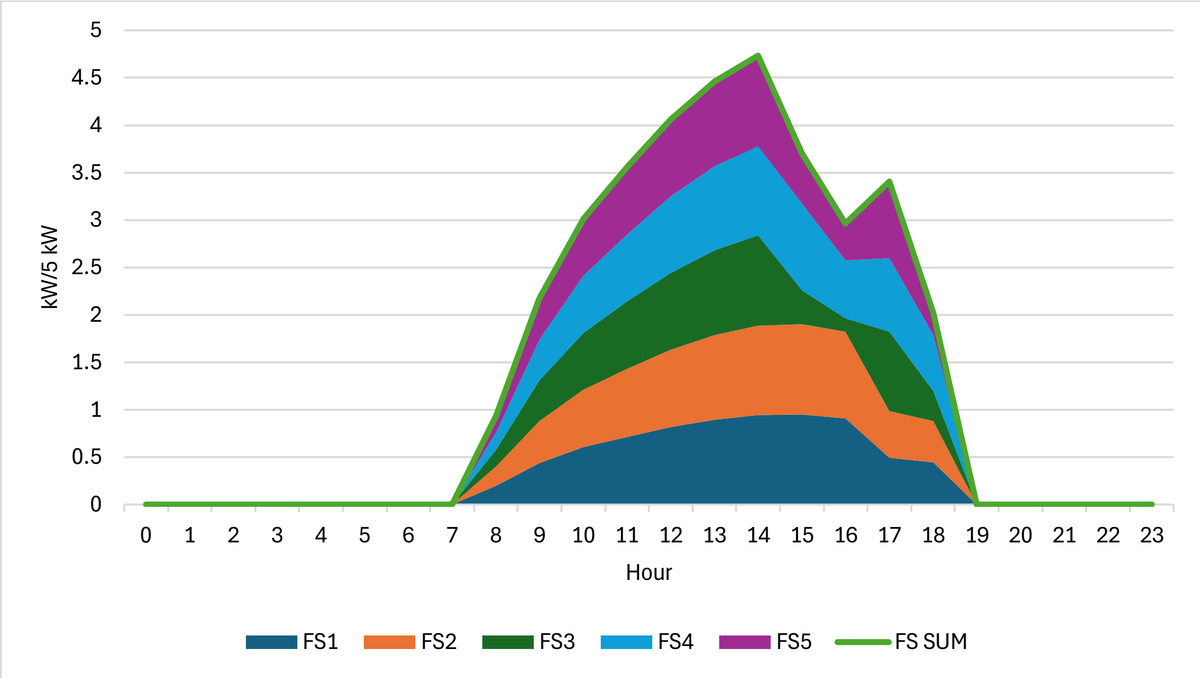


Figure 14: Free State P50 Summer Day Solar PV

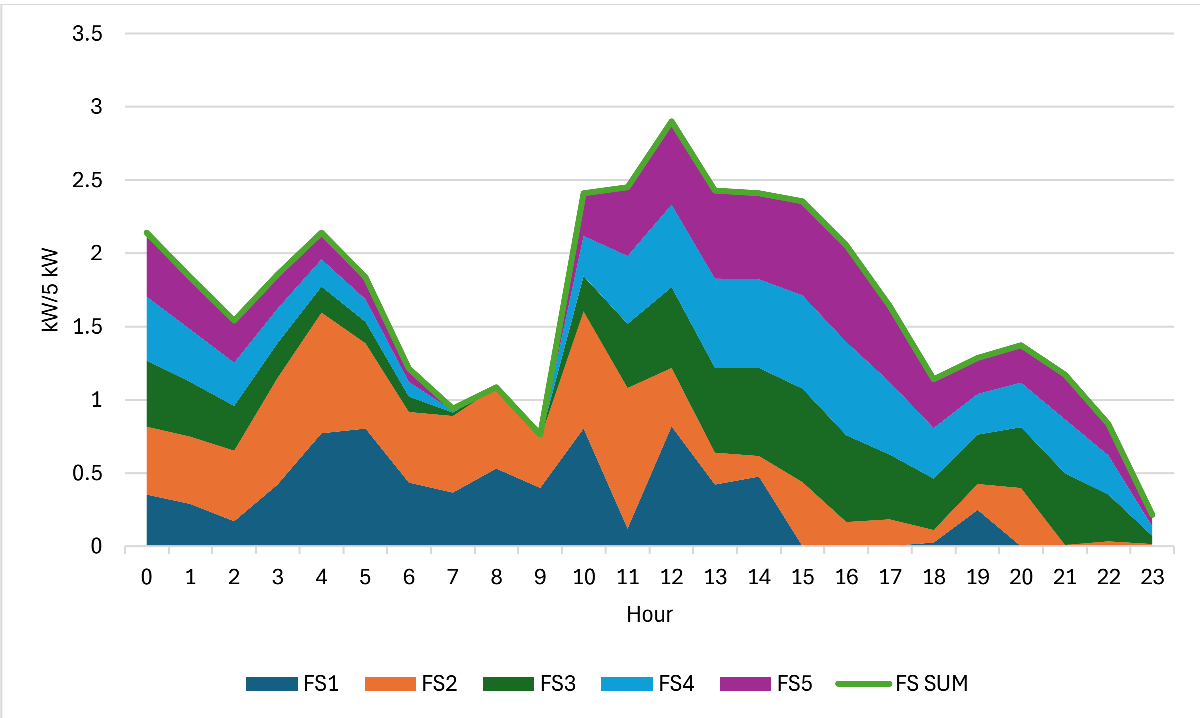


Figure 15: Free State P50 Summer Day Wind

4.3.11 Transmission Corridors

Eskom's existing transmission corridors are high-voltage transmission lines that connect the electricity grids of different regions or provinces, allowing power flow between the supply areas. These transmission corridors were used in the energy model, which was limited to increasing the capacity of existing corridors, as opposed to constructing entirely new corridors. There is no constraint on the extent to which the capacity of these existing corridors can be expanded, and power flow between supply areas is also unrestricted except for the transmission and distribution losses.

Figure 16 shows the ten supply areas marked in red boundary lines and the transmission corridors illustrating power flow between them.

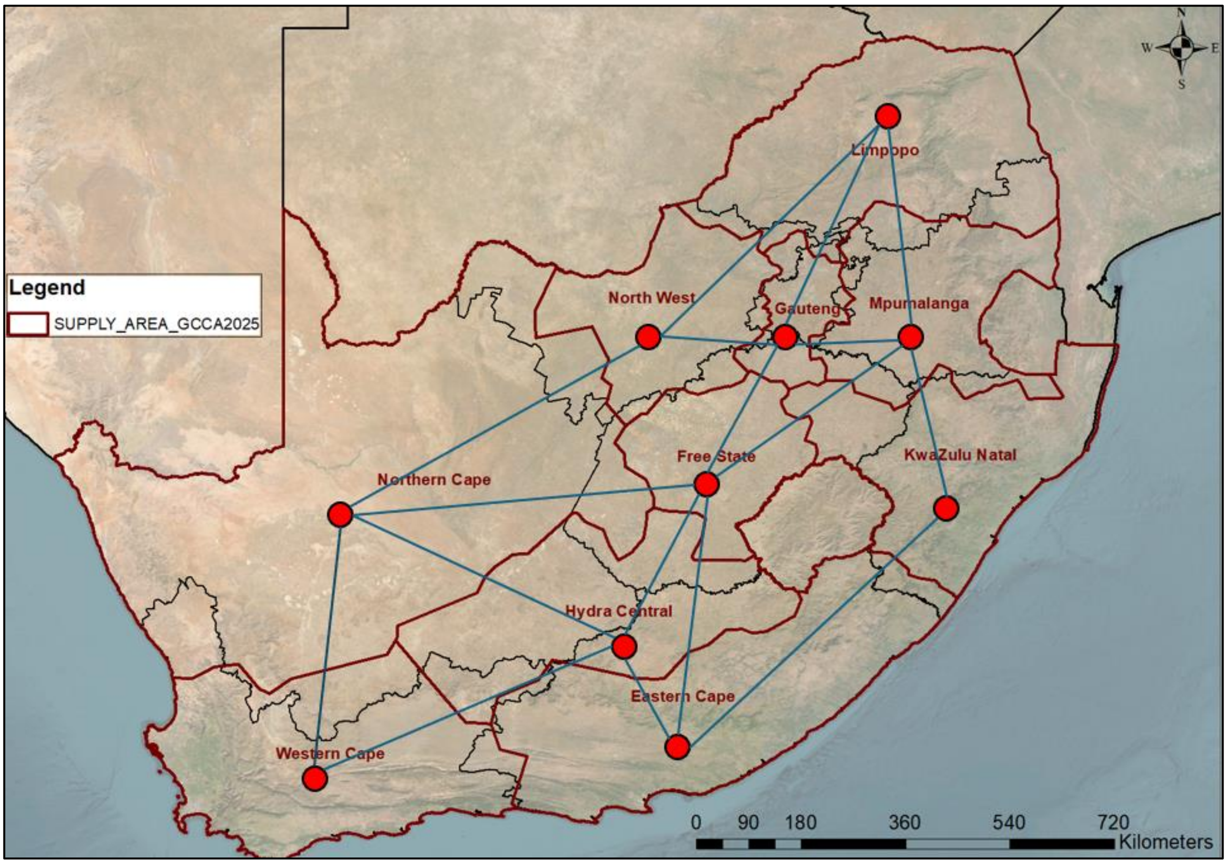


Figure 16: Transmission Corridors

4.3.12 Wind and Solar Collector Networks

VRE sources, such as wind and solar PV plants, are generally distributed and connected via the sub-transmission and distribution networks, which transmit the generated power to the main transmission stations (MTS) and then evacuate via the local transmission corridors to the demand centres. This is different to conventional power plants that have a dedicated transmission station to collect the power, due to typical capacities required exceeding 300 MW). Benefits for retaining the solar and wind facilities below 300 MW include safeguarding the grid against the impact of cloud cover and or wind fluctuation in a localized area, as such this study did not consider the development of mega-solar or wind parks exceeding 1 000 MW per site in the model. This results in additional sub-transmission investment requirements to connect VRE power plants to the grid versus the conventional thermal plants.

4.3.13 Capex Premium as a Proxy for Cost of Capital Premium

Scenarios A and B assume that the cost of capital for new fossil fuel generation exceeds the cost of capital for new renewable energy generation. This assumption reflects current financing trends, where funding for renewable energy projects is more readily available and often at significantly lower cost. For example, concessional finance from institutions such as the Green Climate Fund can be accessed at rates as low as 1%–2%. After hedging and intermediation, these funds may be on-lent by development finance institutions (DFIs) at around 8%. In contrast, no comparable funding streams exist for new coal-fired generation, which faces increasing financing restrictions due to climate-related risk and policy pressures.

The OSeMOSYS energy model lacks the functionality to define different costs of capital for various technologies. Instead, it allows for a global discount rate, which is applied to all future costs in the model (set to 8% across all scenarios). Therefore, an alternative approach was required to incorporate the effect of a higher cost of capital for new fossil fuel technologies. The approach, selected through consultation, was to incorporate a premium on the Capex of new fossil fuel generation as a proxy for the premium on the cost of capital. Thus, the proportionate debt service and equity base will increase in line with the premium on the Capex.

A 10% and 5% Capex premium were applied to new fossil fuel technologies in scenarios A and B, respectively. For example, the expected Capex cost for a new CCGT power plant is 886 USD/kW. In Scenario A, the cost increased to 886 x 110% = 975 USD/kW, and in Scenario B, it increased to 886 x 105% = 930 USD/kW.

To translate the Capex premium into an approximately equivalent increase on the all-in risk premium on debt, a demonstration calculation was conducted, as set out in Table 13. The assumed impact on the all-in risk premium on debt can be calculated assuming that the Capex premium is the same as a premium on the weighted average cost of capital (WACC), and assuming a typical debt or equity split, typical equity rate of return, and current Johannesburg Interbank Average Rate (JIBAR) base rate plus a risk premium.

For Scenario A, a 10% Capex premium translates to a 1.86% increase in the all-in risk premium from 2.44% to 4.30%. For Scenario B, a 5% Capex premium translates to a 1.01% increase in the all-in risk premium from 2.44% to 3.37%.

Note that this approach does not factor in debt tenor, amortization profile, and tax.

Table 13: Capex Premium as Proxy for Cost of Capital Premium

Parameter	Scenario A	Scenario B	Calculation
Equity portion	30.00%	30.00%	(A)
Debt portion	70.00%	70.00%	(B)
Equity rate	20.00%	20.00%	(C)
Debt rate	10.00%	10.00%	(D) = E + F
JIBAR rate	7.56%	7.56%	(E)
All-in risk premium	*2.44%*	*2.44%*	(F)
WACC	13.00%	13.00%	(G) = A x C + B x D
Capex premium proxy	10.00%	5.00%	(H)
Equivalent increased WACC	14.30%	13.65%	(I) = G x (1 + H)
Equity portion	30.00%	30.00%	(J) = A
Debt portion	70.00%	70.00%	(K) = B
Equity rate	20.00%	20.00%	(L) = C
Debt rate	11.86%	10.93%	(M) = N + O
JIBAR rate	7.56%	7.56%	(N) = E
All-in risk premium	*4.30%*	*3.37%*	(O) → goal seek until (P) = (I)
Equivalent increased WACC	14.30%	13.65%	(P) = J x L + K x M = I
All-in risk premium increase	*1.86%*	*1.01%*	(Q) = O - F

4.4 Scenario Results

4.4.1 Capacity

The generation capacity results for **Scenario A** are shown in Figure 17.

In 2030, Scenario A achieves a total generation capacity (excluding battery storage) of approximately 81 GW. Solar contributes approximately 38% of this capacity, wind approximately 22%, coal approximately 17%, and gas approximately 11%, with the remaining capacity contributed by diesel, hydro power, and nuclear sources.

By 2040, the total capacity increases to approximately 152 GW; solar continues to dominate with approximately 44% of installed capacity, wind increases to 26%, coal's share decreases to 9% (same 14 GW as in 2030), and gas increases to approximately 13%.

By 2050, total capacity (again, excluding batteries) reaches approximately 190 GW, with solar expanding to 52%, wind remaining at approximately 25%, gas contributing approximately 12%, and retrofitted coal declining to approximately 5%, with nuclear, hydro power, and diesel making up the remainder.

Battery storage in Scenario A increases substantially from 11 to 31 GW between 2030 and 2040, then to 53 GW by 2050. This represents an approximately 182% increase from 2030 to 2040 and a further 71% increase from 2040 to 2050. Batteries play a key role in absorbing excess VRE, mitigating curtailment, and filling gaps in demand when the VRE resource is low.

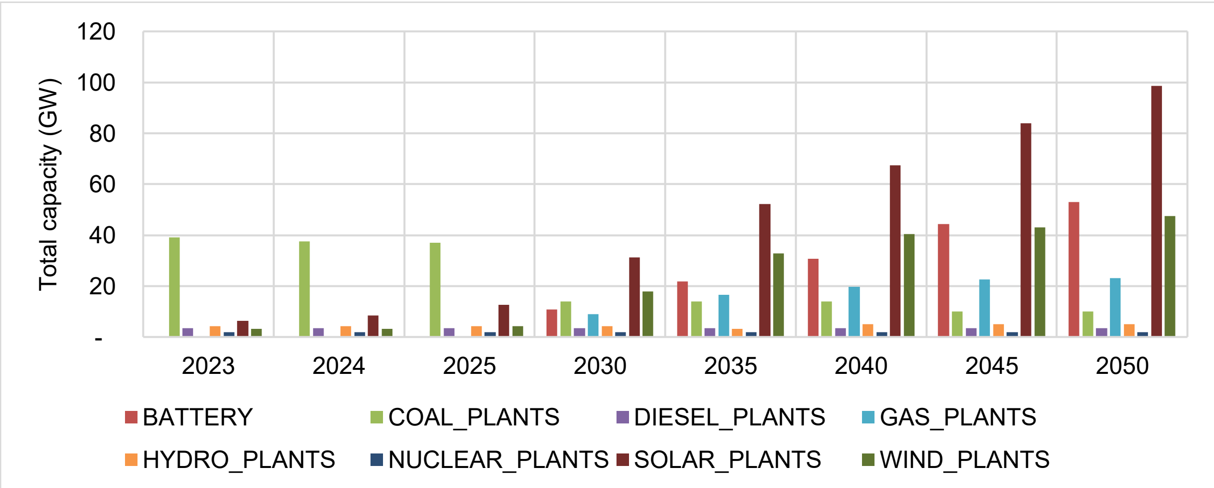


Figure 17: Scenario A Generation Capacity

Scenario B generation capacity results are shown in Figure 18.

In 2030, Scenario B achieves a total capacity of approximately 82 GW, where coal dominates at 42%, solar contributes 26%, and wind provides 13% of the capacity mix. Gas represents 9% of the capacity, and notably, battery deployment is only 2 GW at this stage, indicating an increased reliance on gas and coal to supplement VRE during this period.

By 2040, as AQ retrofits trigger the decommissioning of older coal plants, the coal contribution declines to approximately 9% of the total generation capacity, with an increased gas contribution (16% of installed capacity) and VRE substantially increasing (from 39% to 65% of installed capacity between 2030 and 2040).

By 2050, the dispatch mix is heavily dominated by VRE, with solar and wind contributing approximately 68% of total installed generation. Gas remains a significant dispatchable source at approximately 18%, while coal with CCS contributes a minor 7% of installed capacity. Nuclear and hydro power provide approximately 1% and 3% of installed capacity, respectively.

By 2050, Scenario B builds slightly more gas-fired capacity (26 GW total) and notably less VRE (97 GW total) compared to Scenario A.

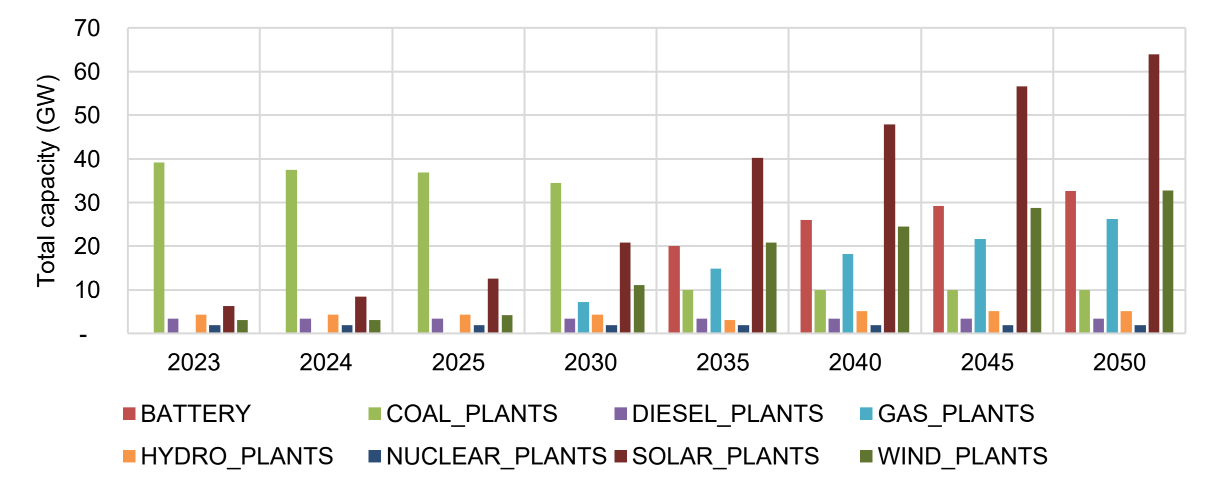


Figure 18: Scenario B Generation Capacity

The generation capacity results of **Scenario C** are shown in Figure 19.

In 2030, Scenario C has a total capacity of 83 GW, with coal accounting for 41% of the capacity mix. Solar contributes 28% of installed capacity, wind contributes 12%, and gas contributes 6%. This indicates that the system is still heavily reliant on coal between 2025 and 2030.

By 2040, the total capacity in Scenario C increases to 109 GW. Solar increases to 38% of installed capacity and wind to 21%. Coal's share declines to 14%, and gas rises to 17%, reflecting a slower transition away from fossil fuels due to a delayed coal decommissioning schedule.

By 2050, the total capacity in Scenario C reaches 134 GW. In this configuration, solar remains at approximately 38% of installed capacity, wind increases to 24%, gas increases to 22% and coal decreases to 6%. Batteries in Scenario C increase from 7 to 46 GW between 2030 and 2040, and further to 55 GW by 2050, which is a dramatic increase of over 500% from 2030 to 2040, followed by a modest increase of 20% from 2040 to 2050. Despite this, the overall system places a lower emphasis on battery-supported VRE integration compared to scenarios A and B.

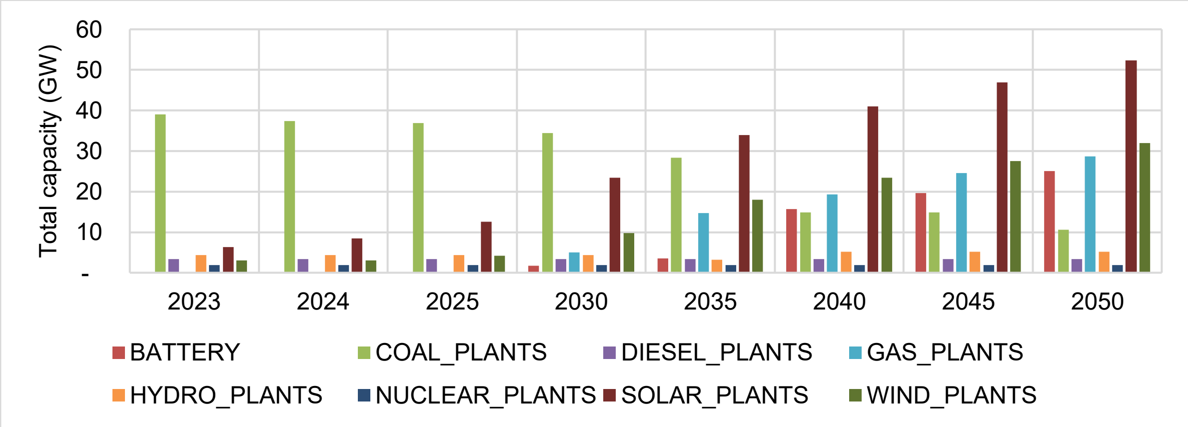


Figure 19: Scenario C Generation Capacity

Figure 20 presents a comparison of the operational generation capacity from each scenario in 2050. The overall trends are as expected given the underlying assumptions for each scenario. These trends and assumptions are as follows:

- **Scenario A**, with optimistic learning rates for VRE, a higher carbon tax, and a Capex premium (as proxy for higher cost of capital) on new fossil fuel capacity, results in the highest VRE and BESS capacity, and the lowest fossil fuel capacity.
- **Scenario B** represents a middle-of-the-road approach between scenarios A and C.
- **Scenario C**, with pessimistic learning rates for VRE, a reduced carbon tax, and no Capex premium on new fossil fuel capacity, results in the lowest VRE and BESS capacity, and the highest fossil fuel capacity.

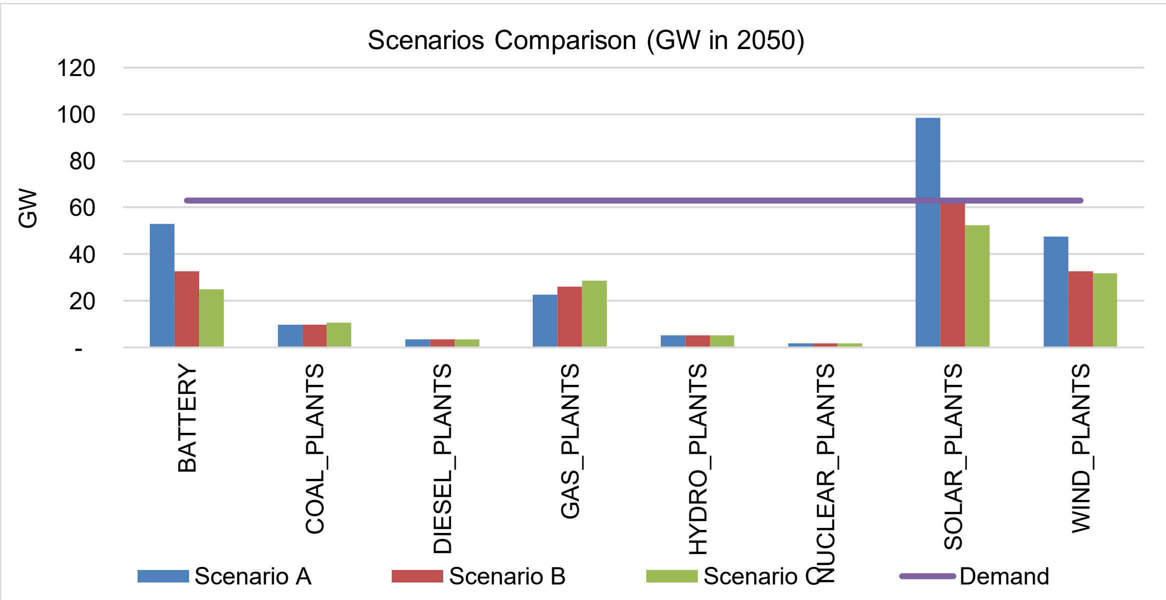


Figure 20: Total Operational Capacity per Scenario

Figure 21 presents a comparison of the average annual build rate of new power generation and storage capacity per scenario over the period from 2025 to 2050. As expected, Scenario A requires the highest and most sustained annual build rates, followed by Scenario B, and finally Scenario C.

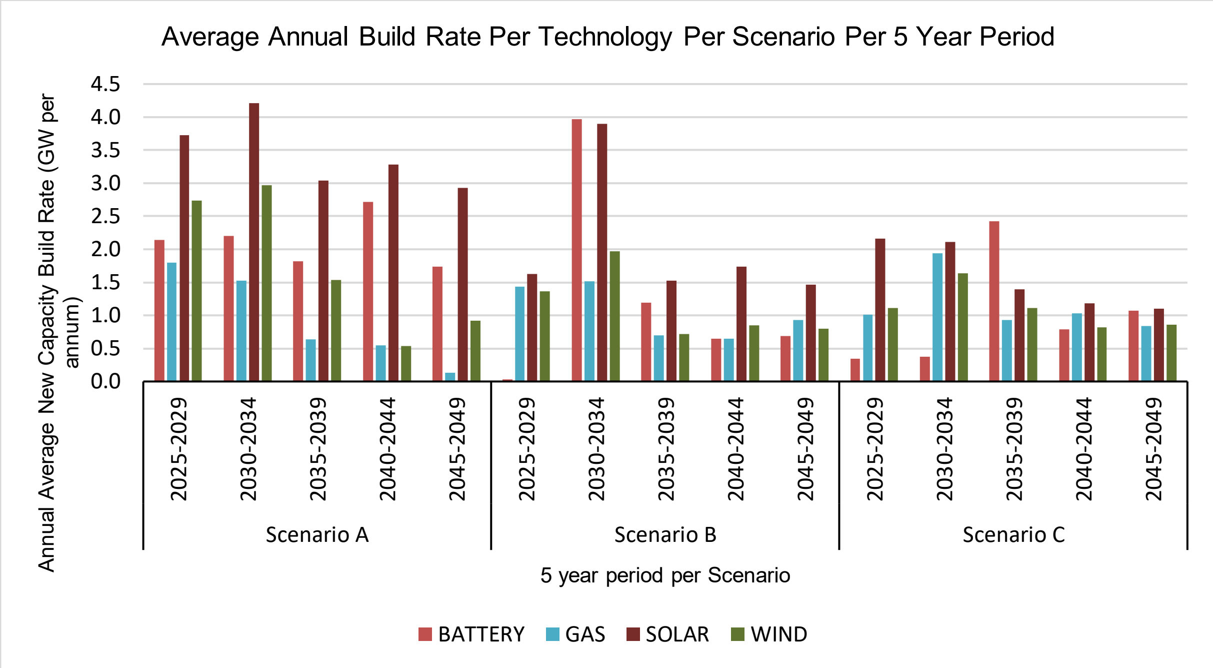


Figure 21: Average Annual New Power Generation Build Rate per Scenario

4.4.2 Dispatch and Energy Mix

The energy mix for **Scenario A** is shown in Figure 22.

In 2030, the demand is 261 TWh, with coal remaining a significant part of the energy mix and contributing 40% (104 TWh). The gas contribution is minimal at 5% (12 TWh), while nuclear and hydro power contribute 6% (15 TWh) and 5% (14 TWh), respectively. Renewable energy sources play a crucial role, with solar making up 30% (77 TWh) and wind contributing 23% (59 TWh).

By 2040, the energy mix will undergo a significant transformation, with coal declining to 10% (32 TWh) as older plants are decommissioned. Gas decreases to 3% (8.8 TWh), while hydro remains steady at 3% (10 TWh). Nuclear holds at 4% (15 TWh), while solar increases to 49% (166 TWh) and wind increases to 40% (136 TWh). The shift towards renewables is accompanied by a substantial increase in battery storage, which reaches 81 TWh. This additional battery storage assists in balancing intermittent power generation from renewable energies.

By 2050, the transition to renewables is nearly complete. The coal (retrofitted with CCS) contribution declines further to 9% (40 TWh), gas capacity increases to support the high renewable energy penetration and contributes 5% (20 TWh), and hydro contributes 2% (9 TWh). Nuclear remains stable at

4% (15 TWh), but the system is now overwhelmingly dominated by renewables, with solar accounting for 57% (242 TWh) and wind contributing 38% (162 TWh). Battery storage expands to 122 TWh, thus playing a key role in system stability and energy shifting.

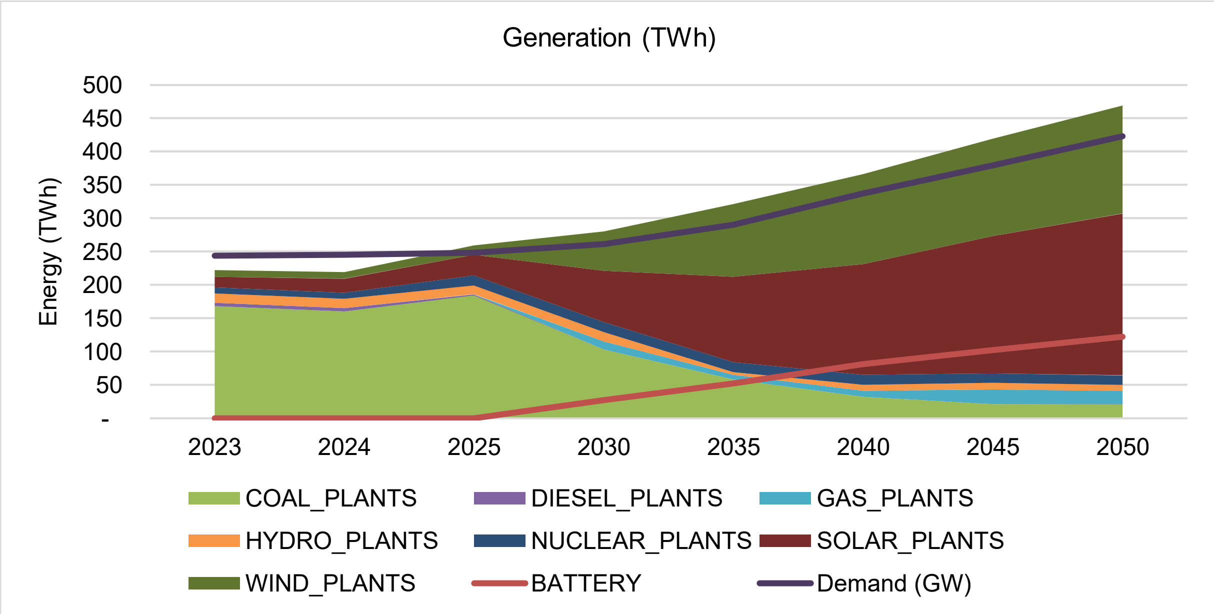


Figure 22: Scenario A Energy Mix

The 2050 dispatch profile for Scenario A is shown in Figure 23. A high penetration of VRE sources characterizes the dispatch profile. Coal and nuclear generation are operated with a consistent load factor. VRE is supplemented by gas-fired generation and energy storage (BESS and potentially PHS) to manage intermittency. The dispatch profile exhibits pronounced diurnal patterns, with solar PV peaking during daylight hours. Wind contributes variably throughout the day. BESS is primarily charged from excess VRE during the day and generally discharged during the evenings. Even with BESS, a curtailment of VRE generation is observed, which is expected from a power system with high penetration of VRE. Approximately 7.5% VRE curtailment in 2050 was estimated for Scenario A using FlexTool.

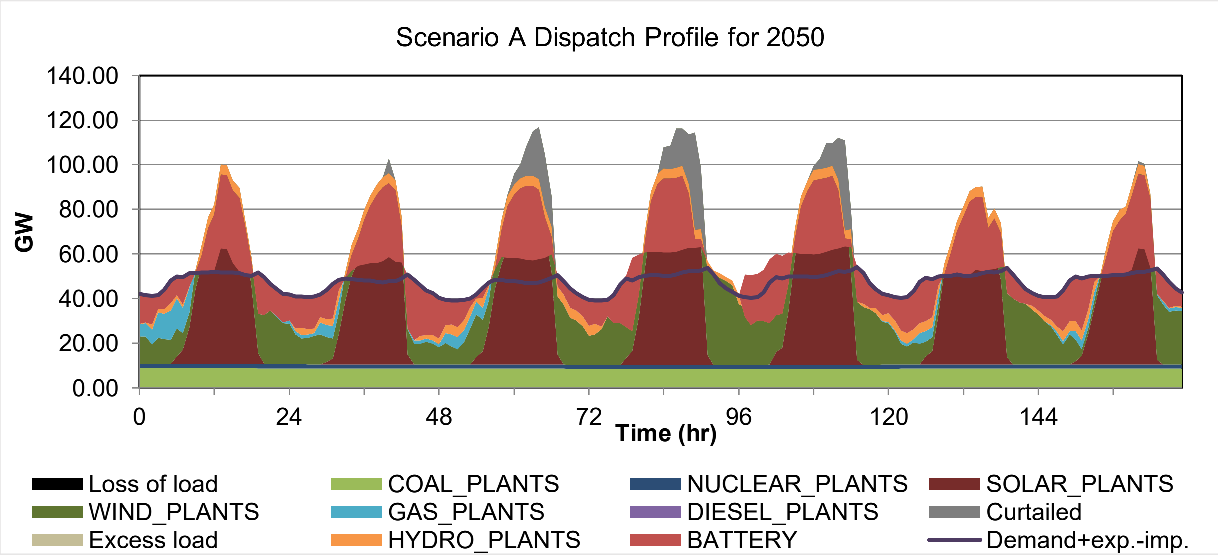


Figure 23: Scenario A Dispatch Profile

The energy mix for **Scenario B** in 2050 is shown in Figure 24.

In 2030, Scenario B maintains a stronger reliance on fossil fuels, with coal generation at 61% or 158 TWh of the total 261 TWh. Gas provides only 2% (5 TWh), nuclear and hydro remain at 6% (15 TWh) and 5% (14 TWh), respectively. The share of renewables is lower compared to Scenario A, with solar making up 20% (51 TWh) and wind contributing 14% (37 TWh). Battery storage plays a minor role, contributing only 1 TWh at this stage.

By 2040, coal generation drops significantly to 18% (61 TWh) as coal plant decommissionings accelerate. However, unlike Scenario A, gas increases to 23% (77 TWh), serving as a firm dispatchable source. Hydro and nuclear remain steady at 3% (10 TWh) and 4% (15 TWh), respectively. Renewables continue to grow but at a slower rate than in Scenario A, with solar increasing to 35% (119 TWh) and wind reaching 24% (81 TWh). Battery storage reaches 56 TWh, assisting with the integration of renewables.

By 2050, Scenario B establishes a more balanced, yet fossil fuel inclusive, mix. Coal generation (for plants retrofitted with CCS) remains at 14% (61 TWh), gas increases to 25% (107 TWh), and hydro and nuclear remain at 2% (10 TWh) and 4% (15 TWh), respectively. Although renewables continue to dominate, they are less prominent than in Scenario A, with solar providing 38% (159 TWh) and wind contributing 26% (108 TWh). Battery storage increases further to 70 TWh, improving system flexibility.

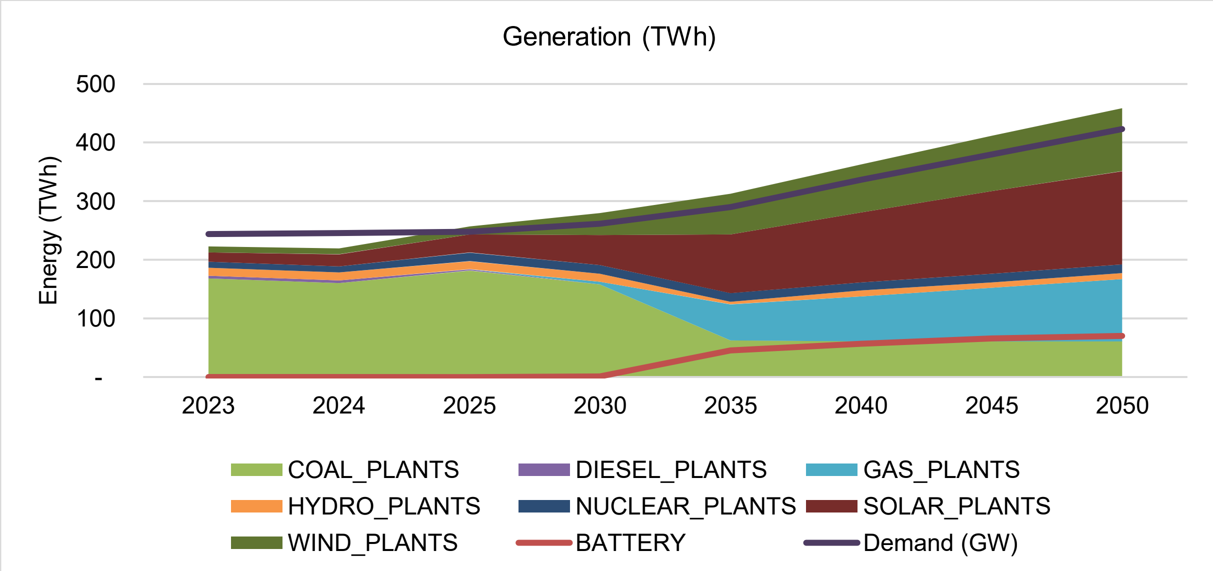


Figure 24: **Scenario B Energy Mix**

The 2050 dispatch profile for Scenario B is shown in Figure 25. The dispatch profile reflects a similar result to Scenario A, with coal and nuclear dispatched at consistent load factors, significant diurnal patterns caused by VRE, and managing the variability of VRE with BESS and gas. Key differences from Scenario A are the more prominent dispatch of gas (due to lower gas prices and a less stringent carbon budget) and the lower VRE curtailment of approximately 3.8%, which was estimated using the FlexTool. This is attributed to the lower VRE capacity versus demand.

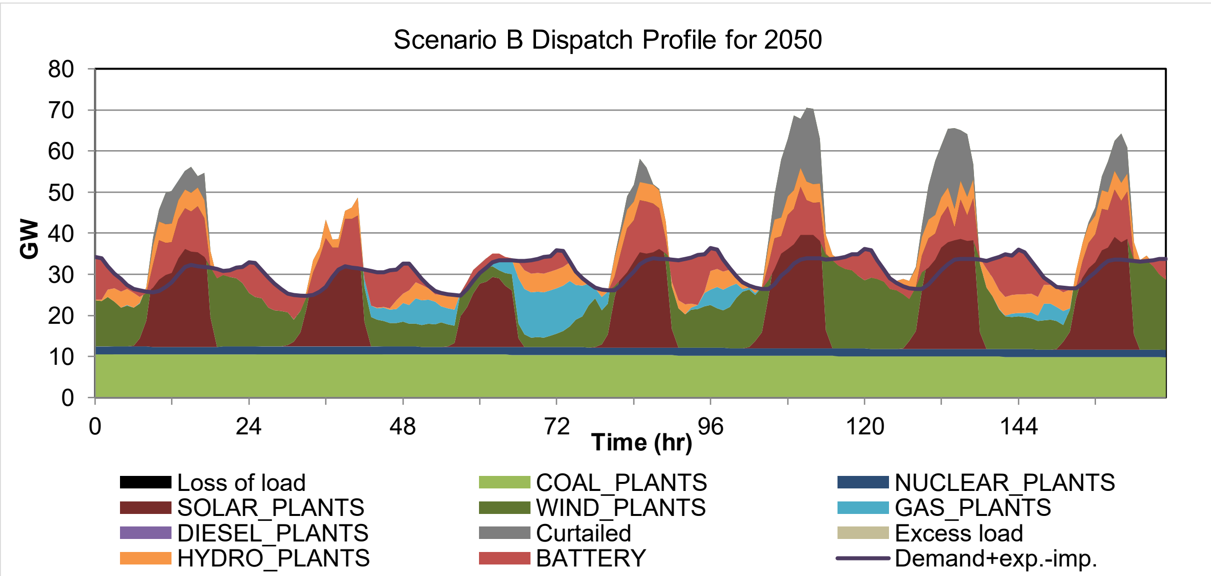


Figure 25: Scenario B Dispatch Profile

The **Scenario C** energy mix is shown in Figure 26.

In 2030, Scenario C retains the highest share of coal generation at 61% or 159 TWh of the total 261 TWh. Gas contributes only 1% (3 TWh), nuclear and hydro provide 5% (14 TWh) each, and renewables make up the remaining share, with solar at 22% (58 TWh) and wind at 12% (32 TWh). Battery storage reaches 7 TWh, slightly improving system flexibility but still playing a limited role.

By 2040, the energy mix remains fossil fuel heavy compared to the other scenarios. Coal declines to 27% (90 TWh), but gas increases significantly to 17% (57 TWh), supporting increased system flexibility. Hydro and nuclear remain at 3% (10 TWh) and 4% (15 TWh), respectively, while solar increases to 30% (101 TWh) and wind rises to 23% (77 TWh). Battery storage plays a more prominent role, reaching 46 TWh, which supports VRE integration.

By 2050, Scenario C still retains the highest coal share at 15% (65 TWh), while gas increases to 28% (118 TWh), making it the most fossil-dependent scenario. Hydro and nuclear remain stable at 2% (10 TWh) and 4% (15 TWh), respectively. Despite the increased contribution of renewable energy, renewables do not achieve the same dominance as in Scenario A. In Scenario C, solar provides 30% (129 TWh) and wind contributes 25% (105 TWh). Battery storage reaches 55 TWh, which helps to manage variability in supply but does not eliminate reliance on gas

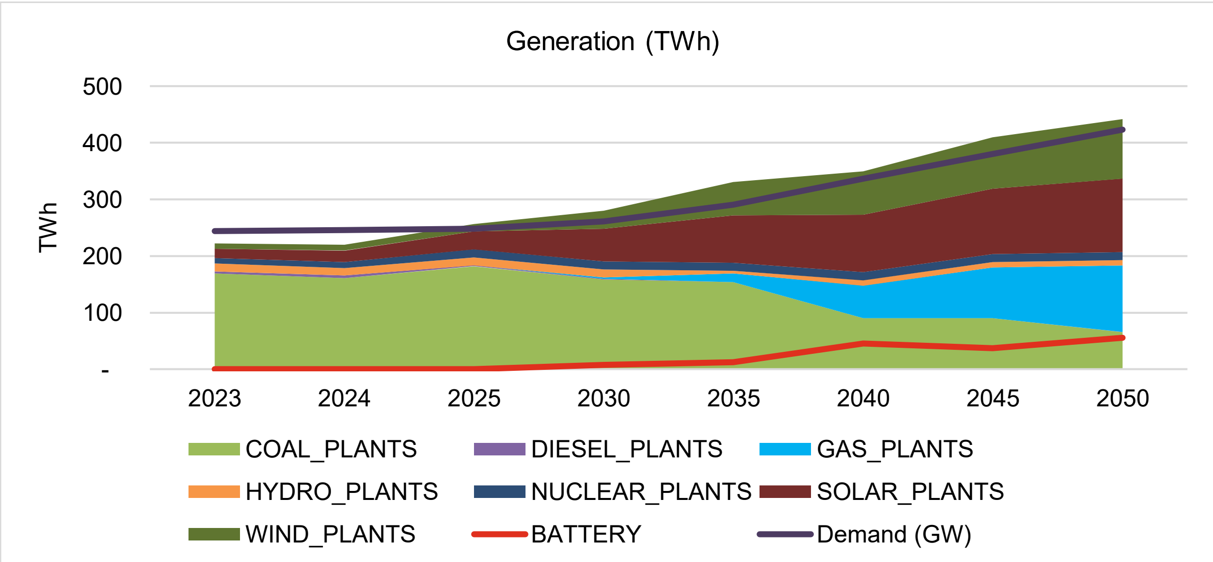


Figure 26: Scenario C Energy Mix

The dispatch profile for Scenario C in 2050 is shown in Figure 27. The dispatch profile reflects a similar result to scenarios A and B, with coal and nuclear dispatched at consistent load factors, significant diurnal patterns present caused by VRE (although less pronounced than scenarios A and B), and the variability of VRE being managed with BESS and gas. Scenario C has the most prominent dispatch of gas due to a lower gas price and no carbon budget, and the lowest VRE curtailment of approximately 0.3% (estimated using FlexTool) due to lower VRE capacity versus demand.

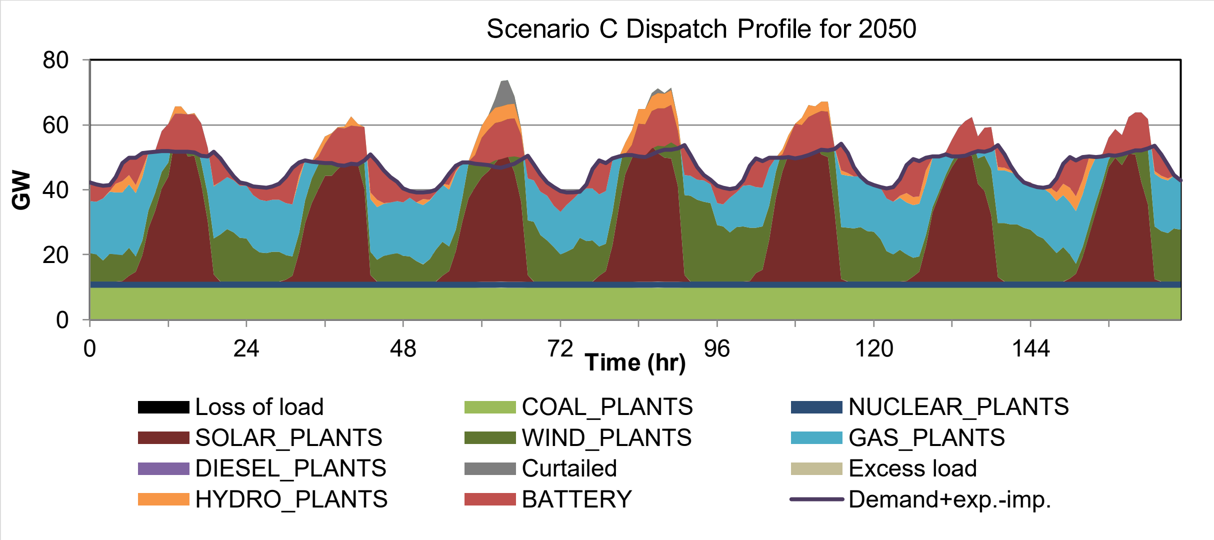


Figure 27: Scenario C Dispatch Profile

4.4.3 Corridor Flows

The figures below depict transmission corridor requirements to facilitate power flow between different supply areas. As shown in Table 14, in all scenarios, the highest power flow is from Free State to Gauteng and Northern Cape to Gauteng via North West, followed by the flow from Hydra Central to Free State, as shown by the red lines connecting the supply areas. In scenarios A and B, significant renewable energy capacity is built, with a larger portion located in the Northern Cape and Hydra Central due to the favourable VRE resource. The transmission corridor then transports this VRE power to the load centre in Gauteng; hence, the biggest transmission corridors are the Northern Cape to Gauteng via the North West corridor and the Hydra Central to Gauteng via the Free State corridor. In addition, power from the Eastern Cape is transported to Gauteng via the Free State – Gauteng / Mpumalanga corridor, and similarly, power from Limpopo is transported to Gauteng via the North West – Gauteng corridor.

Scenario A, being the most aggressive decarbonization pathway with the highest renewable energy build, results in significant transmission capacity requirements across all corridors, particularly those originating from high-resource renewable energy zones. This is evident in the large transmission capacities required between Hydra Central and the Eastern Cape, Northern Cape, and Free State, reflecting the high concentration of wind and solar PV projects in these areas. The high build-out of VRE in the Western and Eastern Cape provinces drives the need for extensive grid reinforcement to export power to inland demand centres such as the Free State and Gauteng. This is depicted in Figure 28 by the dark red line, indicating the highest transmission flows across key corridors relative to the other scenarios.

In Scenario B, transmission expansion between Hydra Central and Eastern Cape, while not as extensive as Scenario A, remains a critical requirement to facilitate the increasing contribution of VRE in the system after coal decommissioning accelerates. This is illustrated in Figure 29 by the orange line, sitting between the aggressive build-out in Scenario A and the more conservative development seen in Scenario C.

Scenario C builds fewer renewable energy projects, resulting in less generation capacity being built in the Hydra Central supply areas. This in turn requires less transmission capacity between Hydra Central and the Free State. This is depicted by the orange line in Figure 30 versus the red line in the other scenarios.

Table 14: Transmission Corridor Capacity per Scenario

Start	End	Corridor Length (km)	Transmission Corridor Capacity (MW)		
			Scenario A	Scenario B	Scenario C
WC	HC	553	6 964	6 732	7 265
HC	EC	411	11 114	6 819	3 034
HC	NC	531	2 466	-	1 693
HC	FS	528	6 592	5 486	8 835
FS	MP	471	5 258	7 186	-
FS	GP	382	35 000	35 000	35 000
NC	NW	647	13 125	11 749	11 677
NW	GP	247	24 807	24 807	24 688
MP	GP	234	20 000	12 027	20 000
KZN	MP	297	-	-	-
EC	KZN	723	-	-	-
LM	NW	629	23 700	29 071	28 490
LM	MP	334	4 359	344	258
FS	NW	369	-	-	-
WC	NC	1039	5 275	5 275	5 250
EC	FS	564	10 022	8 357	5 596
LM	GP	392	22 170	28 635	30 000
NC	FS	682	15 753	11 722	5 271

Start	End	Corridor Length (km)	Transmission Corridor Capacity (MW)		
			Scenario A	Scenario B	Scenario C
Total Capacity			**206 604**	**193 210**	**187 056**

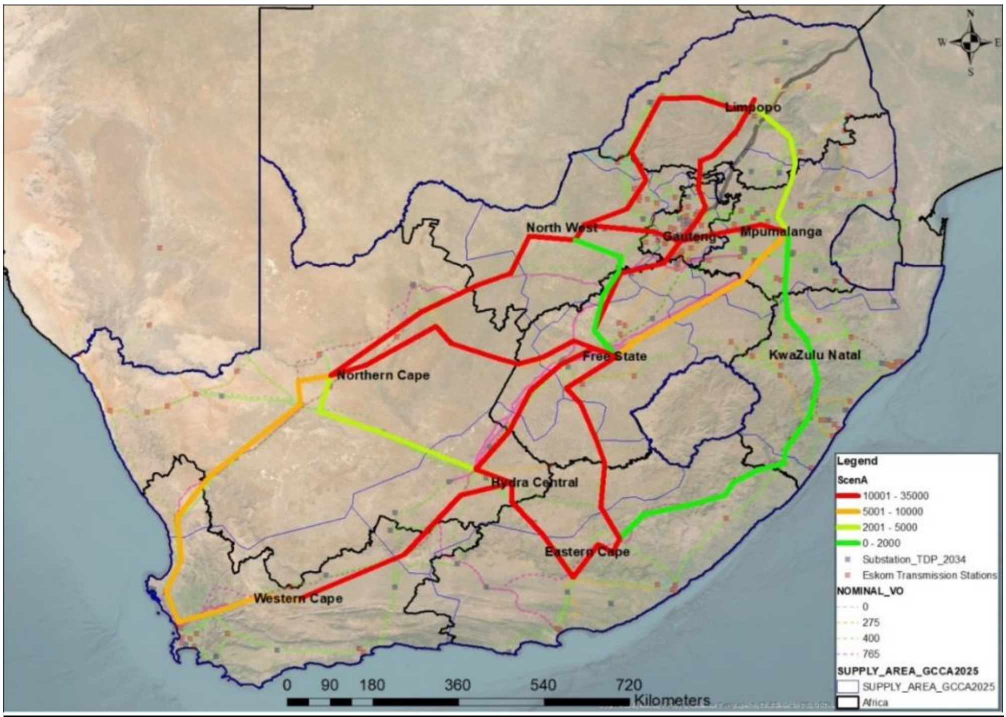


Figure 28: Scenario A Corridor Flows

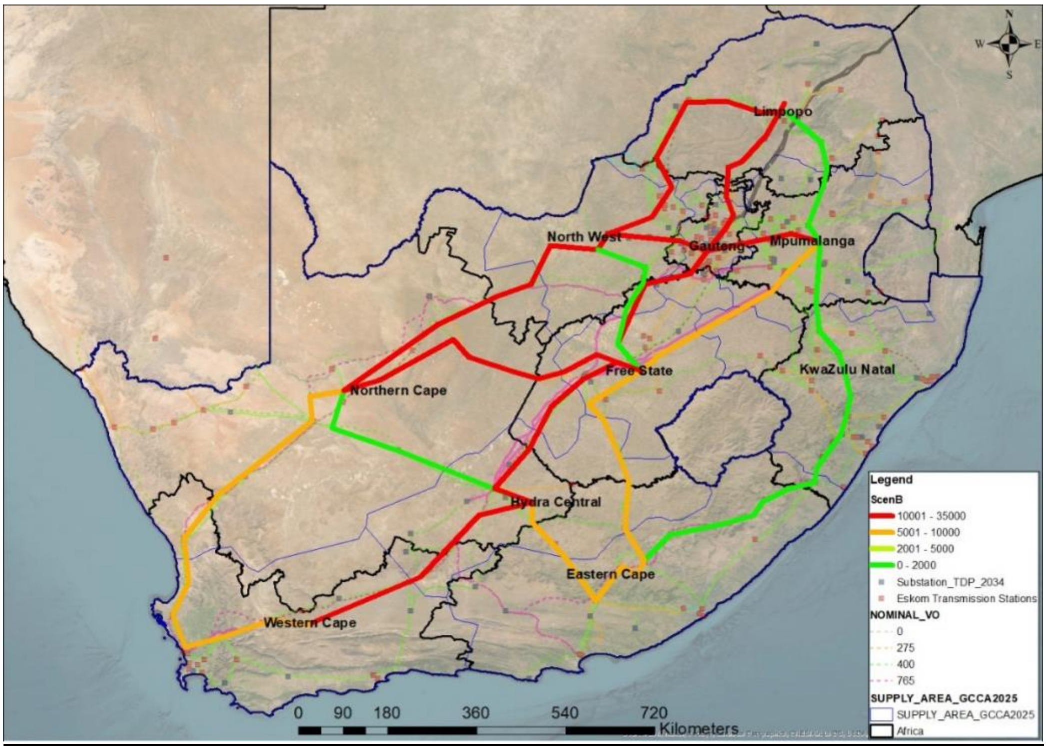


Figure 29: Scenario B Corridor Flows

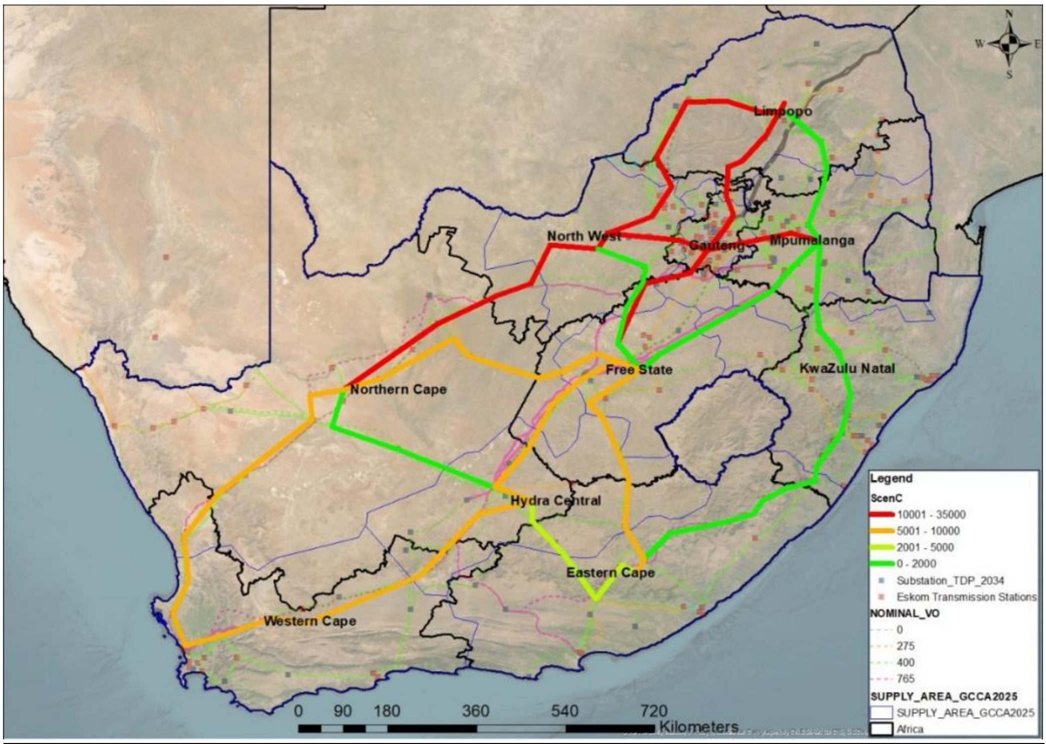


Figure 30: Scenario C Corridor Flows

4.4.4 CO_2 Emissions

Figure 31 illustrates the annual CO_2 emissions across the model period for scenarios A, B, and C.

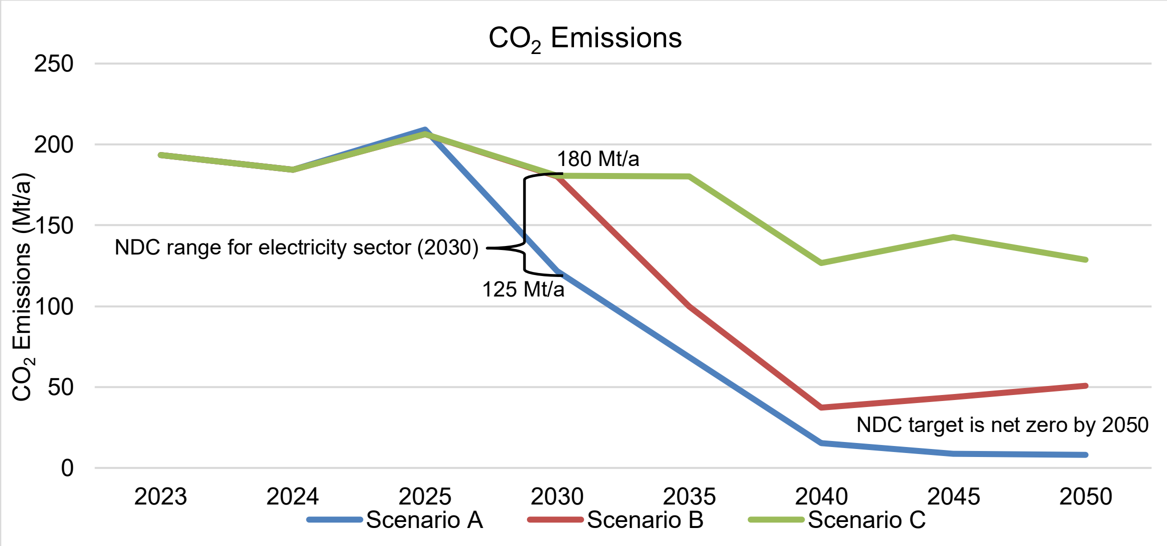


Figure 31: CO_2 Emissions per Scenario

Scenario A results in **2.1 Gt of CO_2 emissions** from 2023 to 2050, slightly exceeding the original target of 2.0 Gt of CO_2 emissions. Coal capacity is phased out rapidly between 2025 and 2040. By 2040, the Medupi, Kusile, and Majuba plants are retrofitted with CCS, while the Kendal, Lethabo, and Matimba plants continue to operate until 2045 without CCS retrofits. Gas is dispatched less frequently in this scenario, as BESS plays a much larger role in supporting VRE, as illustrated in Figure 32.

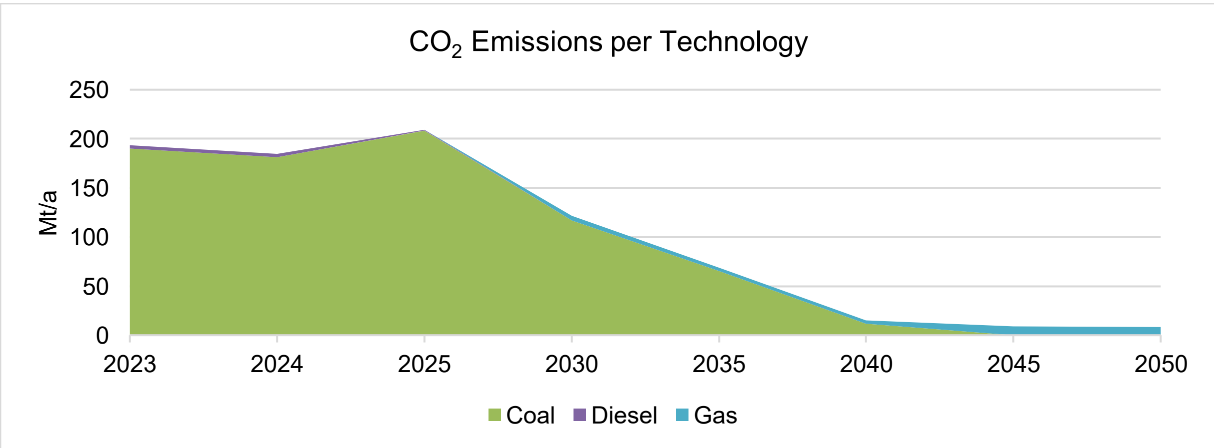


Figure 32: Scenario A CO_2 Emissions per Technology

Scenario B results in **3.1 Gt of CO_2 emissions** from 2023 to 2050, against a target of 3.0 Gt of CO_2 emissions. This scenario adopts a more gradual decarbonization approach, allowing more coal to remain in operation for longer (plants with shorter remaining life close by 2035) and later CCS conversion of coal plants with longer remaining lifetimes (2040). As illustrated by the blue area in Figure 33Figure 33, the relatively higher contribution of gas generation beyond 2040 results in higher emissions between 2040 and 2050 compared to Scenario A.

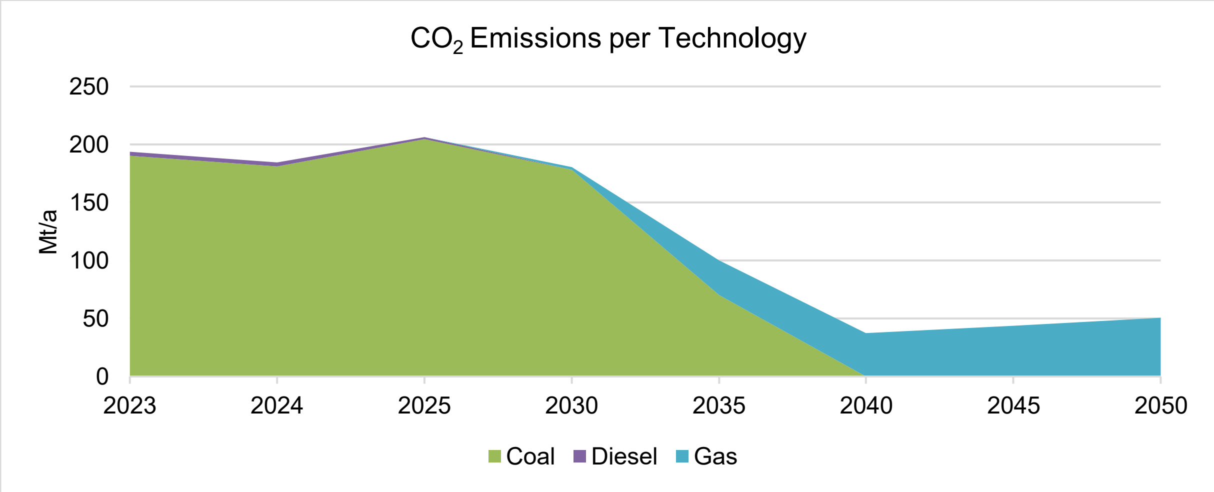


Figure 33: Scenario B CO_2 Emissions per Technology

Scenario C had no CO_2 emissions constraint, which resulted in **4.5 Gt of CO_2 emissions** from 2023 to 2050. With the delayed decommissioning schedule and extended life of the coal fleet and no requirement for AQ retrofits or CCS conversion, the coal fleet remains online for longer and emits much higher quantities of CO_2 emissions, as illustrated by the larger green area in Figure 34 compared to scenarios A and B.

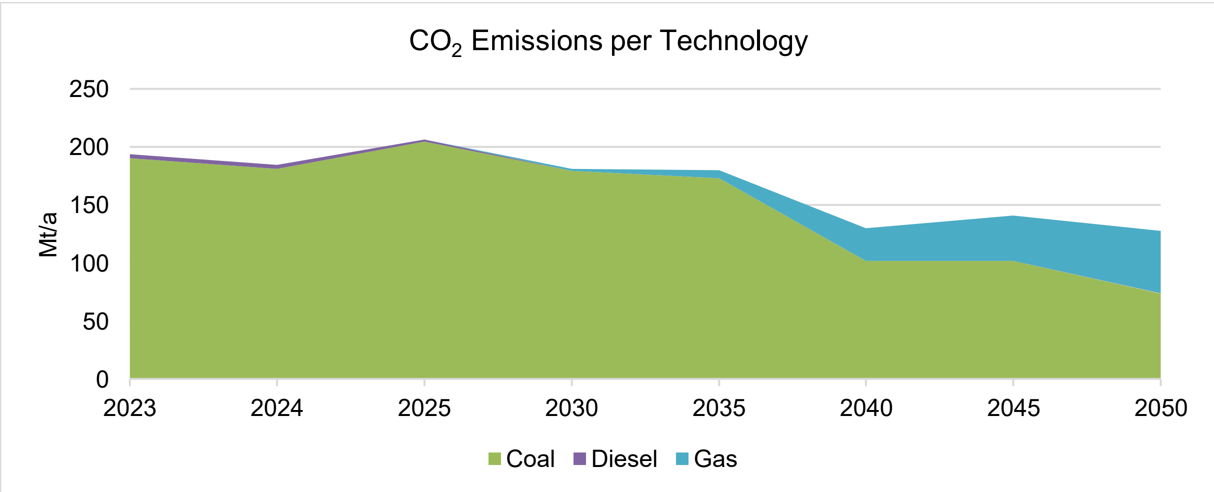


Figure 34: Scenario C CO_2 Emissions per Technology

4.4.5 Generation Costs

All costs in this section, unless stated otherwise, have been discounted by 8% to 2024 real terms, and while the generation mix was optimized based on carbon tax, the carbon tax costs are excluded from the costs presented here.

Throughout this section the cost parameters differ between the three scenarios, e.g., optimistic learning rates adopted in Scenario A versus pessimistic learning rates in Scenario C; lower coal and gas prices in Scenario A versus higher coal and gas prices in Scenario C; higher carbon tax in Scenario A versus lower carbon tax in Scenario C; high Capex premium (as proxy for high cost of capital) on fossil fuel technologies in Scenario A versus no Capex premium on fossil fuel technologies in Scenario C.

Scenario A requires the highest Capex (R1 651 billion) due to the large build of new VRE, BESS, and gas despite the optimistic learning rates for these technologies. However, Scenario A also achieves the lowest total system cost (R3 203 billion), due to the relatively low variable cost (R727 billion). The low variable cost is due to the reduced reliance on fossil fuel generation as well as lower coal and gas prices. The AQ retrofits and subsequent CCS conversions at Medupi, Kusile, and Majuba introduce additional costs, but these are somewhat offset by the lower coal price, as illustrated in Figure 35. Fixed costs are greater than in the other scenarios (R825 billion), despite optimistic technology learning rates for VRE and BESS, due to the much larger generation capacity.

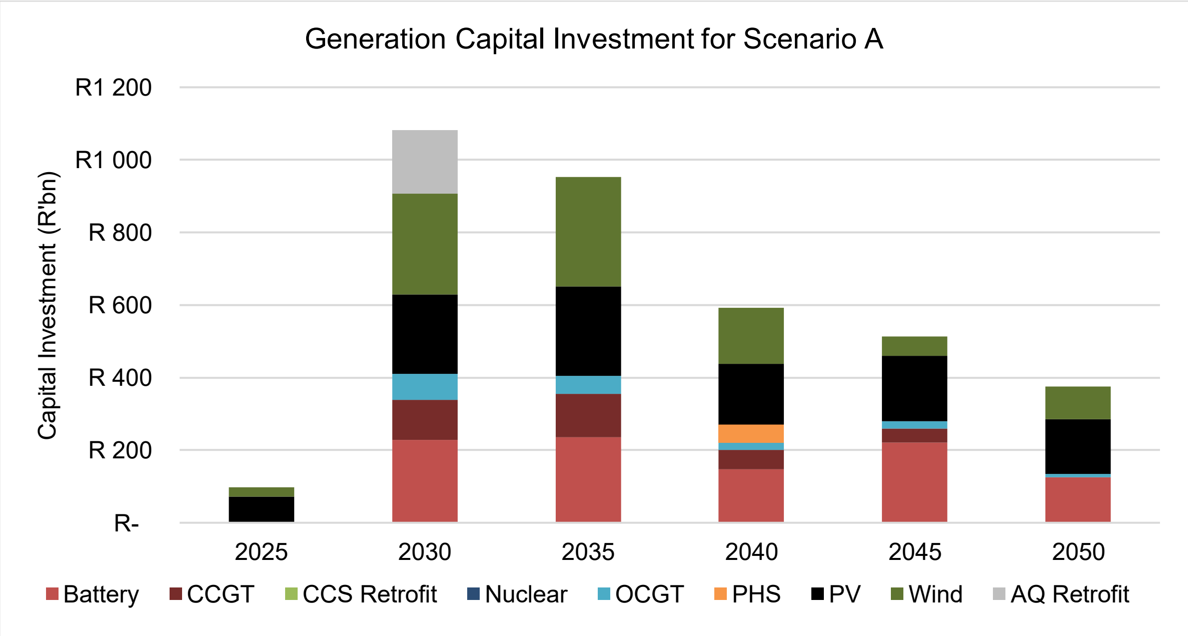


Figure 35: **Scenario A Generation Capital Investment (not discounted)**

Figure 36 below illustrates the generation capital cost for Scenario B**.**

Scenario B has a significantly lower Capex (R1 229 billion) than Scenario A, but higher variable costs (R1 520 billion), leading to a higher total system cost of R3 395 billion. This is the result of a more gradual transition away from coal, later implementation of AQ retrofits (2035) and CCS (2040), and reduced new power generation capacity compared to Scenario A. The medium gas and coal prices contribute to higher variable operational costs compared to Scenario A, as fossil fuel generation contributes a larger part of the energy mix. Additionally, with a lower Capex premium (as a proxy for cost of capital) on fossil fuel technologies compared to Scenario A, more gas capacity is built, further increasing variable costs.

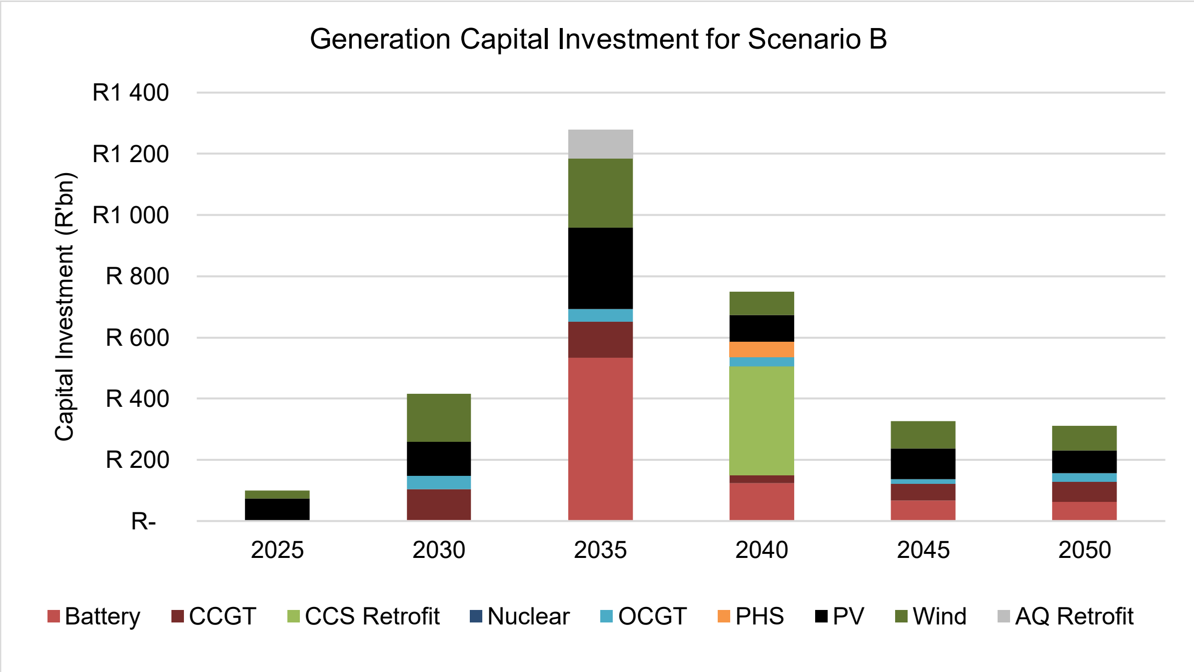


Figure 36: **Scenario B Capital Investment (not discounted)**

Scenario C requires a Capex of R1 446 billion, which is higher than Scenario B but lower than Scenario A. Even though Scenario C builds the least amount of new capacity, the pessimistic technology learning rates cause the Capex to be higher than Scenario B, as illustrated in Figure 37. The total system cost (R3 935 billion) is the highest among the scenarios due to significantly higher variable costs (R1 814 billion). This is attributed to a prolonged dependence on coal, higher dependence on gas, and higher prices for both coal and gas prices. With no AQ or carbon constraints in place, AQ retrofits and CCS conversions are deemed unnecessary, and coal plants continue to operate without modification. The lower Capex premium on fossil fuel technologies further incentivises construction of new gas generation, leading to the highest gas dispatch among the scenarios. The fixed cost component (R675 billion) is comparable to other scenarios, because of the reduced new capacity (which decreases fixed costs) being offset by pessimistic technology learning rates (which increase fixed costs).

A comparison of the capital investments for the three scenarios is illustrated in Figure 38 below.

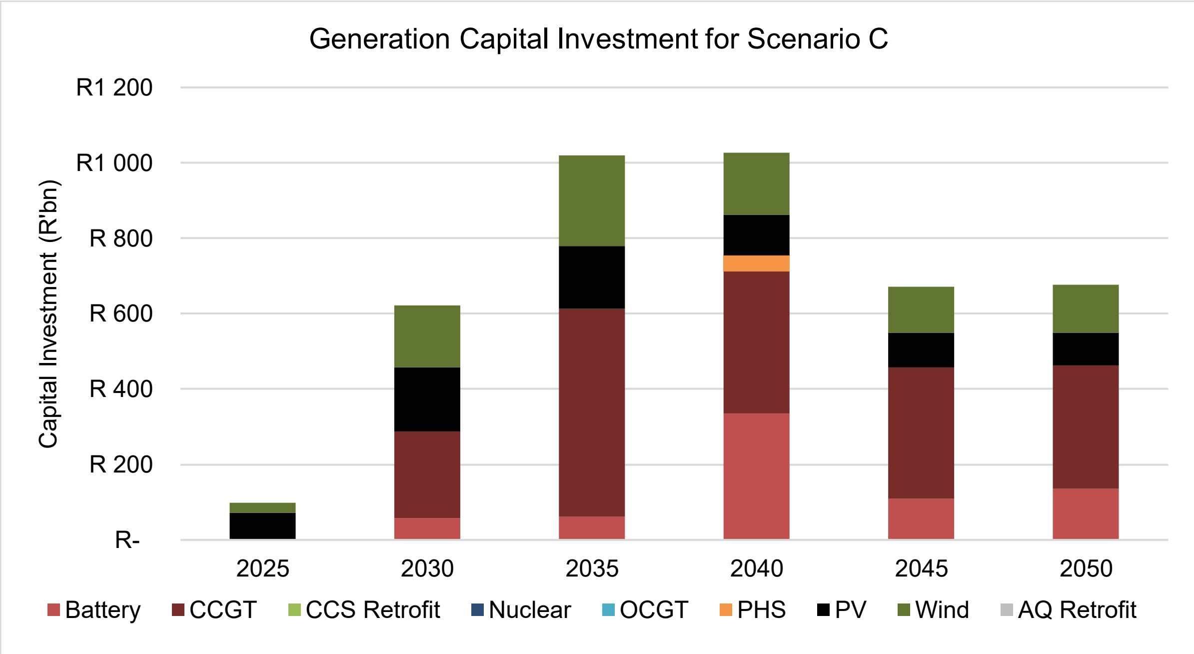


Figure 37: Scenario C Capital Investment (not discounted)

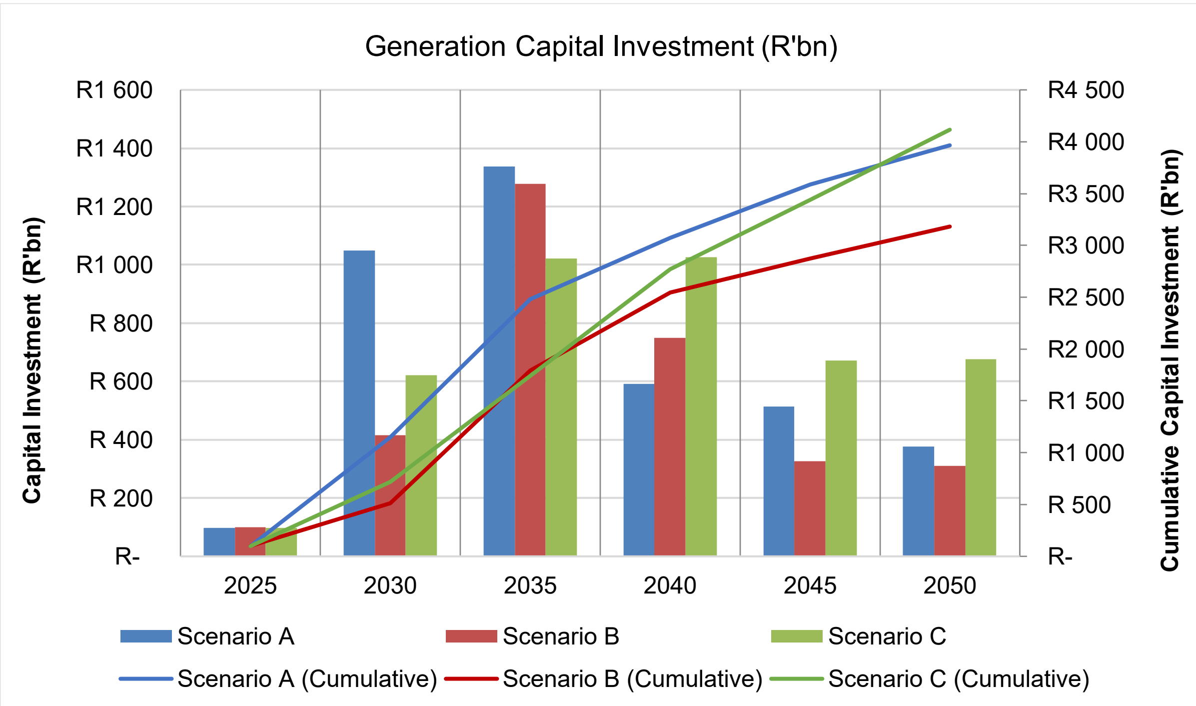


Figure 38: Generation Capital Investment per Scenario (not discounted)

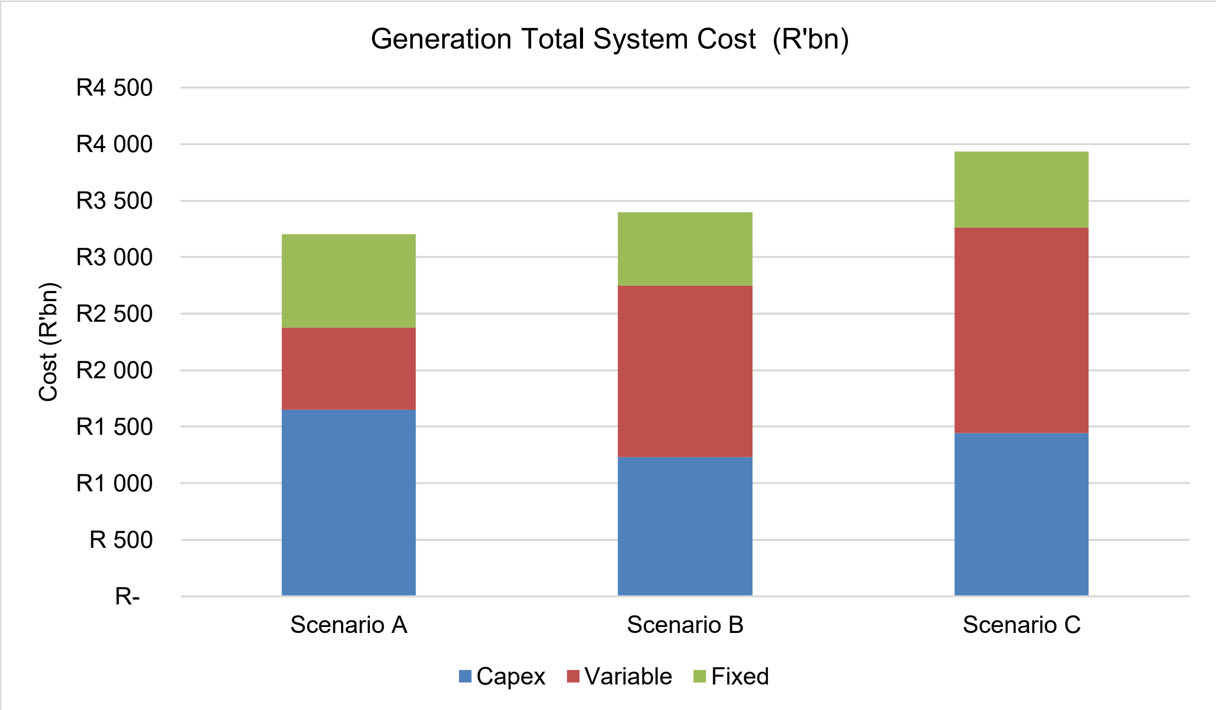


Figure 39: Generation Total System Cost per Scenario (discounted 8% to 2024 real terms)

Generation costs can be summarised with the following comparative insights:

- **Capex trends**: Scenario A incurs the highest Capex due to its aggressive build-out of VRE and BESS, while scenarios B and C opt for more incremental transitions, leading to lower Capex. The pessimistic technology learning rates adopted for Scenario C translated to higher Capex than Scenario B, despite the smaller quantum of new capacity.
- **Variable costs**: Scenario C bears the highest variable cost due to its continued reliance on fossil fuels, coupled with higher coal and gas prices, while Scenario A benefits from lower fuel prices and a higher penetration of renewable energy.
- **Fixed costs**: These are similar for all scenarios as the quantum of generation capacity (highest in Scenario A and lowest in Scenario C) is offset against the different technology learning rates (optimistic in Scenario A and pessimistic in Scenario C).
- **Total cost considerations**: As illustrated in Figure 39, Scenario A achieves the lowest total system cost due to reduced reliance on fossil fuel generation and lower fuel prices, despite its high Capex. Scenario C, while delaying upfront investments, incurs the highest long-term or total system cost due to continued fossil fuel generation, higher fuel prices, and pessimistic technology learning rates.

The generation cost results reflect system-level modelling outcomes based on technology-specific capital and operating cost assumptions, and do not fully incorporate the cost of capital[15] or financing considerations. In practice, the ability to raise capital and the cost at which it can be raised will likely vary between technologies and project types. For example, the cost to obtain capital to keep the existing coal fleet operational includes refurbishment and AQ compliance retrofit costs, which may come at a premium compared to capital raised for new renewable energy infrastructure.

4.4.6 Grid Costs

South Africa's transition to a low-carbon energy system requires significant grid expansion to integrate renewables, maintain reliability, and support demand centres. Transmission corridor capacities vary across scenarios, reflecting differences in renewable energy integration and fossil fuel reliance (see Section 4.4.3).

The grid investment costs presented in this study include both transmission and distribution infrastructure. The TDP produced by Eskom focuses exclusively on the transmission network, which is now operated by NTCSA following the recent unbundling of Eskom. This study also accounts for the significant investment required in distribution collector networks to integrate VRE into the grid. These distribution investments are substantial in scenarios involving large-scale renewable deployment and currently lack a formal planning document equivalent to the TDP. Therefore, while the total grid expansion costs shown here may appear significantly higher than those in the TDP, this is because they also include estimates for distribution costs, which are not captured in the TDP.

Figure 40 provides a comparison and breakdown of the total grid expansion costs required per scenario by 2050. The total grid expansion costs differ significantly across the three scenarios. Scenario A requires the highest investment, at R922 billion (not discounted), due to the extensive expansion of the substation and distribution network required for large-scale renewable integration. Scenario B follows with a cost of R630 billion (not discounted), reflecting the reduced capacity of new power generation compared to Scenario A. Scenario C has the lowest grid investment at R555 billion, as it relies on existing transmission infrastructure rather than integrating substantial new VRE sources.

Figure 40: Total Grid Cost per Scenario (not discounted)Figure 40 shows that the distribution collector networks, required for the connection of new renewable energy sources, contribute a large portion of the total grid cost. In Scenario A, which has the largest quantum of new renewable energy, the cost of new distribution collector networks comprises 53% of the total grid cost, which is greater than the collective cost of all new transmission infrastructure, including backbones, collection lines, and substation.

[15] Cost of capital differences between renewable and fossil fuel technologies are somewhat catered for by applying a Capex premium, as a proxy for cost of capital premium, to fossil fuel technologies in some scenarios, as discussed in Section 4.3.13.

Distribution collector networks in scenarios B and C comprise 47% and 43% of the total grid cost, respectively.

Using non-discounted costs to compare the total grid cost against the total system cost (where total system cost is the sum of total grid costs and total generation costs), the total grid costs are 19%, 17%, and 12% of the total system cost for scenarios A, B, and C, respectively. The total grid cost as a proportion of the total system cost is the highest for Scenario A due to the significant distribution collector network costs required for the large quantum of new renewable energy and BESS capacity.

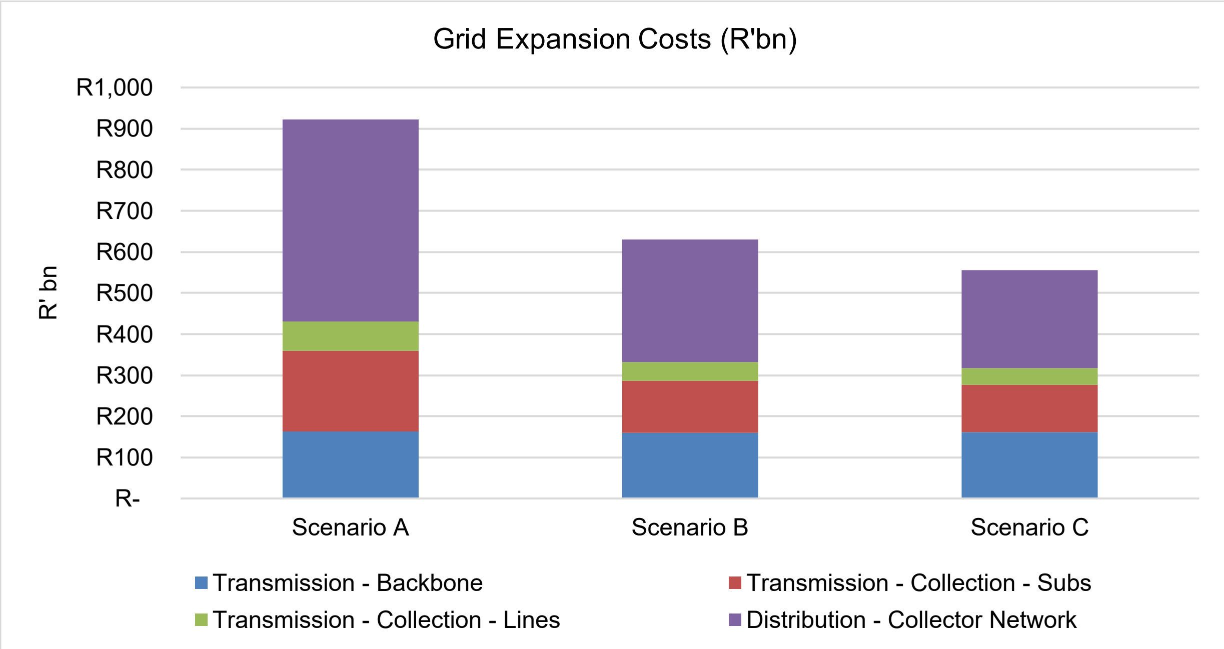


Figure 40: Total Grid Cost per Scenario (not discounted)

4.4.7 Summary

The Table 15: Results Summary provides a side-by-side comparison of key input assumptions and output results per scenario, including capacity and cost.

Figure 41, Figure 42, and Figure 43 provide a one-page summary of the key results from scenarios A, B, and C, respectively.

Table 15: Results Summary

Area	Model parameter or descriptor	Scenario A Green Industrialization	Scenario B Market Forces	Scenario C Business-as-usual
INPUTS				
Policy and regulations	Carbon emissions target	2.0 $GtCO_2e$	3.0 $GtCO_2e$	No limit
	Adherence to AQ standards	Mandated by 2030	Mandated by 2035	Not mandated
	CBAM and other export market regulations[16]	Fully aligned, high impact on export market	Partial alignment (global disconnect), though reduced, export market stays largely intact	Partial alignment (local and global disconnect), current export markets stay intact
	CO_2 tax	As per Draft IRP 2023 2026: USD 16, 2030: USD 25, 2040: USD 50, 2050: USD 100	As per Draft IRP 2023 2026: USD 16, 2030: USD 25, 2040: USD 50, 2050: USD 100	Reduced 2026: USD 16, 2030: USD 25 2040: USD 45, 2050: USD 66
Generation	Coal fleet decommissioning	Pathway 1 (IRP 2019, with adjustments) (UPGEM, December 2023)	Pathway 1 (IRP 2019, with adjustments) (UPGEM, December 2023)	Pathway 2 (Delayed decommissioning timeline relative to pathway 1) (UPGEM, December 2023)
	Coal fleet EAF	High 65% from 2023 to 70% by 2035, 70% to end, excluding Medupi and Kusile, which are 73% from 2025	Medium 65% throughout, excluding Medupi and Kusile, which are 73% from 2025	Low 60% throughout, excluding Medupi and Kusile, which are 73% from 2025

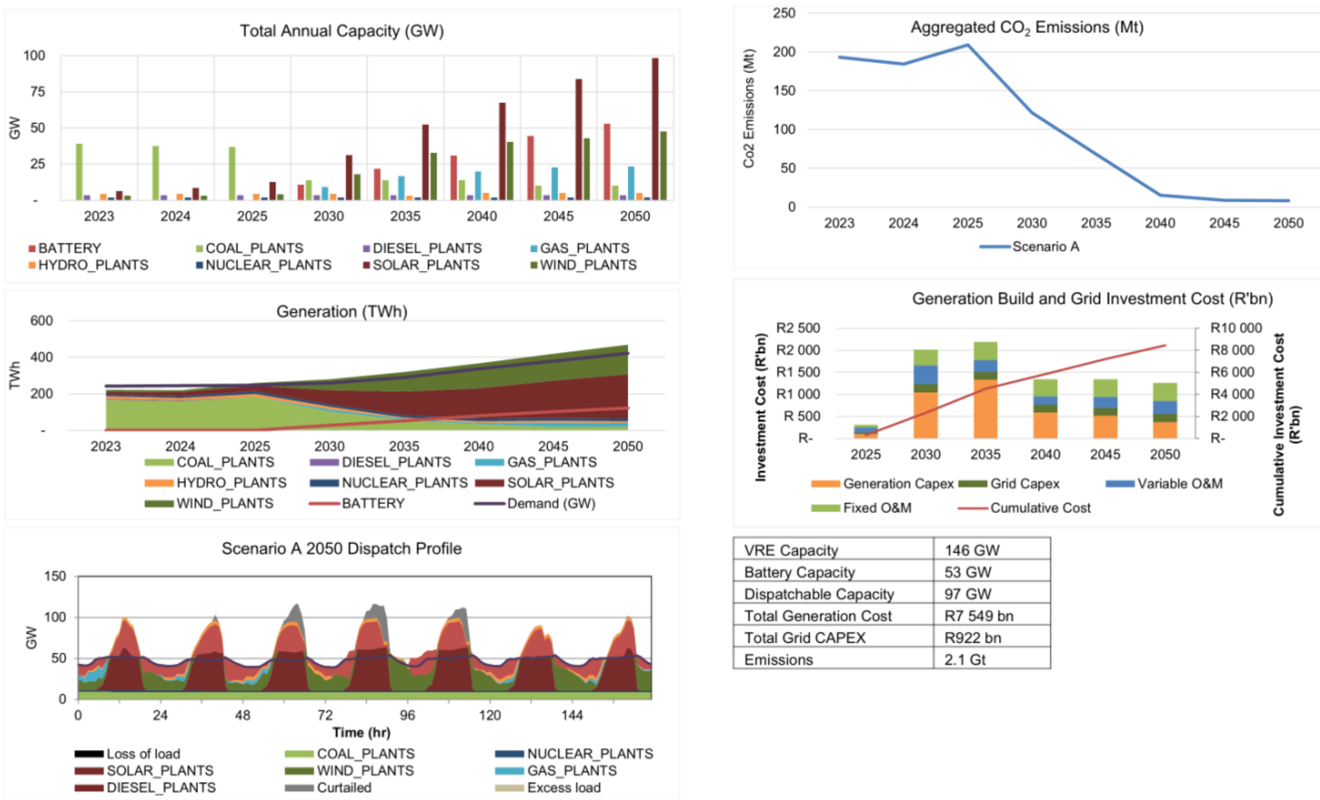
[16] *Descriptor of the external environment, as opposed to a modelling input.*

Area	Model parameter or descriptor	Scenario A Green Industrialization	Scenario B Market Forces	Scenario C Business-as-usual
	Carbon capture and storage (CCS)	Option for coal power plants from 2035	Option for coal power plants from 2040	Option for coal power plants from 2040
	Technology costs and learning rates	Optimistic Likely scenario from Meridian Economics, Review of the IRP 2023 (2024)	Moderate Base Case scenario from Meridian Economics, Review of the IRP 2023 (2024)	Pessimistic Stress scenario from Meridian Economics, Review of the IRP 2023 (2024)
Fuel Prices	Coal and natural gas	Low NZE scenario from IEA (2024)	Moderate APS scenario from IEA (2024)	High STEPS scenario from IEA (2024)
Capital	Size of market and funding[17]	Significant local and international funding available for zero carbon generation options. Little/ no finance for carbon intensive generation (but more available for gas vs coal).	Local and international funding available for zero carbon generation options. Finance for carbon intensive generation is more expensive.	Limited local and international funding available for zero carbon generation options. Finance for carbon intensive generation is even more expensive.
	Cost of capital	10% Capex premium added to new fossil fuel technologies (as a proxy for higher cost of capital)	5% Capex premium added to new fossil fuel technologies (as a proxy for higher cost of capital)	Cost of capital is equal for new renewable energy and new fossil fuel technologies
OUTPUTS				

[17] *Descriptor of the external environment, as opposed to a modelling input.*

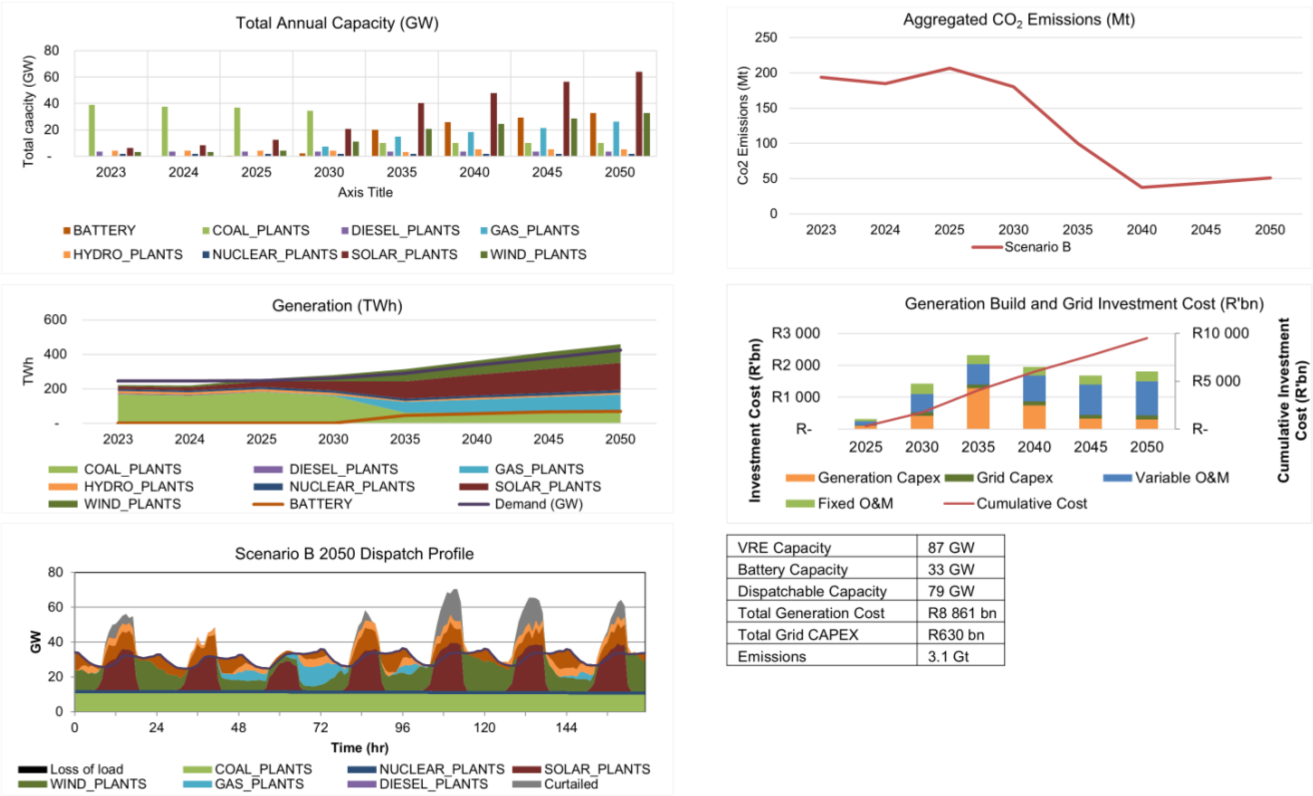
Area	Model parameter or descriptor	Scenario A Green Industrialization	Scenario B Market Forces	Scenario C Business-as-usual
Capacity (GW)	2030	Solar: 31 Wind: 18 BESS: 11 Gas: 9 Coal: 14 Hydro: 4 Nuclear: 2	Solar: 21 Wind: 11 BESS: 2 Gas: 7 Coal: 34 Hydro: 4 Nuclear: 2	Solar: 23 Wind: 10 BESS: 2 Gas: 5 Coal: 34 Hydro: 2 Nuclear: 2
	2040	Solar: 67 Wind: 40 BESS: 31 Gas: 20 Coal: 14 (including 10 GW with CCS) Hydro: 5 Nuclear: 2	Solar: 48 Wind: 24 BESS: 26 Gas: 18 Coal: 10 (with CCS) Hydro: 5 Nuclear: 2	Solar: 41 Wind: 23 BESS: 16 Gas: 19 Coal: 15 Hydro: 5 Nuclear: 2
	2050	Solar: 99 Wind: 48 BESS: 53 Gas: 23 Coal: 10 (with CCS) Hydro: 5 Nuclear: 2	Solar: 64 Wind: 33 BESS: 33 Gas: 26 Coal: 10 (with CCS) Hydro: 5 Nuclear: 2	Solar: 52 Wind: 32 BESS: 25 Gas: 29 Coal: 11 Hydro: 5 Nuclear: 2
Carbon Emissions	Resultant Carbon Emissions (2023 to 2050)	2.1 GT	3.1 GT	4.5 GT
Cost (discounted 8% to 2024 real terms)	Generation Cost	R3 203 262 million	R3 394 635 million	R3 935 063 million
	Grid Cost	R383 234 million	R262 023 million	R230 853 million

Area	Model parameter or descriptor	Scenario A Green Industrialization	Scenario B Market Forces	Scenario C Business-as-usual
	Total Cost (Difference from A)	R3 586 496 million (0%)	R3 656 658 million (+2%)	R4 165 916 million (+16%)



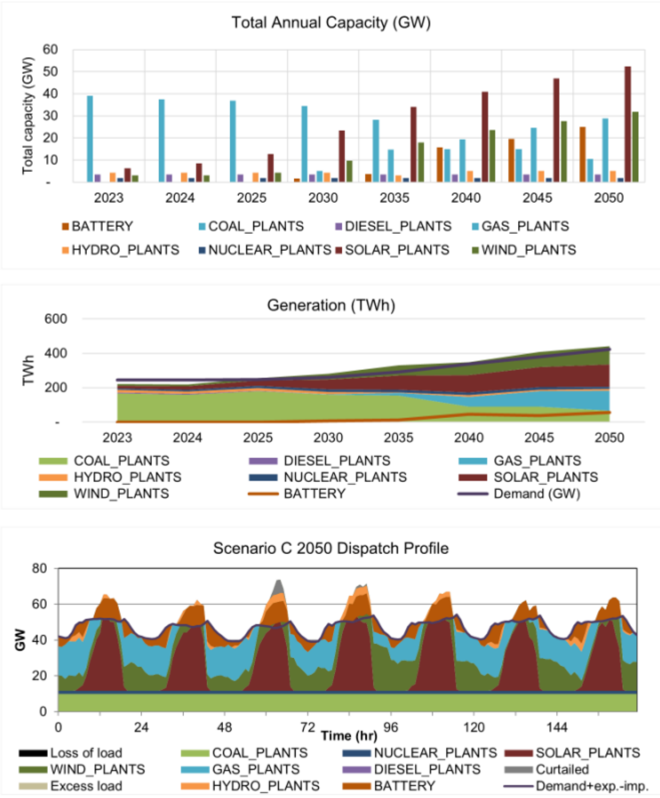
VRE Capacity	146 GW
Battery Capacity	53 GW
Dispatchable Capacity	97 GW
Total Generation Cost	R7 549 bn
Total Grid CAPEX	R922 bn
Emissions	2.1 Gt

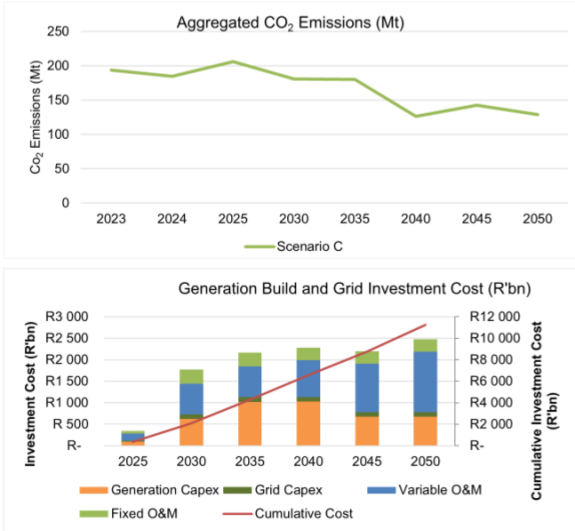
Figure 41: Consolidated Summary for Scenario A (not discounted)



VRE Capacity	87 GW
Battery Capacity	33 GW
Dispatchable Capacity	79 GW
Total Generation Cost	R8 861 bn
Total Grid CAPEX	R630 bn
Emissions	3.1 Gt

Figure 42: Consolidated Summary for Scenario B (not discounted)





VRE Capacity	84 GW
Battery Capacity	25 GW
Dispatchable Capacity	75 GW
Total Generation Cost	R10 677 bn
Total Grid CAPEX	R 555 bn
Emissions	4.5 Gt

Figure 43: Consolidated Summary for Scenario C (not discounted)

4.5 Sensitivity Analyses

4.5.1 Methodology

The energy modelling sensitivity analyses examine how key policy, economic, and technical uncertainties impact the findings presented in this study. By varying key input parameters, including fuel prices, technology costs, carbon taxation, and coal fleet performance, the analysis assesses the robustness of the capacity expansion, dispatch profile, and cost structure under different conditions. Each sensitivity analysis tests a specific assumption, highlighting the impact on system costs, generation mix, emissions, and investment decisions.

Scenario B was selected as the base case for sensitivity analysis because it represents a middle-of-the-road approach between scenarios A and C. Each sensitivity is modelled by adjusting a single key parameter while keeping all other assumptions aligned with Scenario B as summarised in Table 16. This approach isolates the impact of individual variables on capacity expansion, dispatch, and system costs. The model optimizes the generation mix based on least-cost principles while adhering to emissions constraints, fuel price fluctuations, and technology learning rates.

Table 16: Sensitivities Descriptions

Sensitivity	Name	Purpose
-	Scenario B (Market Forces)	Base case
1	No Growth until 2040	What is the capital cost required just to replace the decommissioned coal fleet by 2040 with no increase in demand?
2	Medium TDP Demand	What happens if one reduces the demand growth rate from the IRP 2023 reference case (CAGR: 2.1%) to Medium TDP Demand (CAGR: 1.9%)?
3	0% Premium on Fossil Fuel Generation Technologies	What happens if one removes the 5% capex premium applied to fossil fuel technologies?
4	10% Premium on Fossil Fuel Generation Technologies	What happens if one increases the capex premium applied to fossil fuel technologies to 10%?
5	30% Premium on Fossil Fuel Generation Technologies	At what capex premium applied to fossil fuel technologies will new nuclear capacity be deployed?
6	Low EAF	What happens if the EAF of the Eskom coal fleet (excluding for Medupi and Kusile) remains at 60% and never improves?
7	Delayed Coal Decommissioning	What happens if one forces the Eskom coal fleet decommissioning dates to be extended?

Sensitivity	Name	Purpose
8	No AQ Retrofits in 2035	What happens if AQ retrofits are never mandated?
9	Pessimistic Learning Rate	What happens if one adopts the pessimistic learning rates for VRE and BESS technologies?
10	Higher CCS Capex	At what Capex cost is CCS no longer selected in the energy mix?
11	Lower Coal Price (-60%)	What happens if coal prices are 60% lower than the base case? (From R45/GJ to R18/GJ?)
12	Higher Gas Price (+30%)	What happens if gas prices are 30% higher than the base case? (From R200/GJ to R260/GJ?)
13	Reduced Carbon Tax	What happens if the carbon tax is reduced? (From 104 to 68 USD/ton CO_2 in 2050?)
14	Increased Carbon Tax	What happens if the carbon tax is increased? (From 104 to 188 USD/ton CO_2 in 2050?)

4.5.2 Results for the Sensitivity Analyses

The sensitivity analyses reveal distinct trends across groups of parameters relative to the base case in Scenario B. The differences in cost breakdowns (see Figure 45) show the full range of total generation costs for all scenarios and sensitivity cases. Table 17 summarises the differences in capacity per technology type for each sensitivity, and Table 18 provides a comparison of generation costs, including carbon tax costs.

The Medium TDP Demand scenario, which adopts a slightly reduced growth rate compared to the IRP 2023 Reference Case, results in a modest decrease in required capacity while maintaining a similar generation mix.

When examining the impact of Capex premiums on fossil fuel power plants (as a proxy for the premium on the cost of capital), the analysis shows that removing the 5% premium on fossil fuel technologies makes conventional generation more attractive, leading to increased gas capacity at the expense of renewables. Increasing this premium to 10% shifts investment towards more renewables and storage, whereas a significantly higher 30% premium is required before the model chooses to deploy new nuclear capacity.

A reduced EAF for the coal fleet forces the system to compensate by dispatching more gas, but only for a relatively short period until 2030, after which most of the coal fleet is decommissioned. Inversely, delaying coal decommissioning and forcing coal plants to remain online until their end of life reduces near-term investments in renewable and gas energy. However, this necessitates a much larger reduction in CO_2 emissions in the long term to adhere to the 3.0 $GtCO_2$ emissions budget. Similarly, if AQ retrofits are not mandated, older coal plants continue to operate for longer, delaying the transition to alternative generation technologies.

CCS is deployed for Medupi, Kusile, and Majuba power stations in most sensitivities. CCS capital costs must be 1.5 to 2 times greater than the current expected costs for the model to decommission these plants and replace the generation with other technologies instead of deploying CCS.

Renewables and BESS feature heavily in every sensitivity. While a pessimistic learning rate for VRE and BESS technologies results in less new renewable capacity, these technologies still see the largest quantum of new power generation capacity and contribute more than 50% of the energy mix by 2050 in that sensitivity.

Regarding fuel prices, lower coal prices result in coal plants being decommissioned later and coal contributing more towards the energy mix between 2030 and 2040. However, by 2045 and 2050, the energy mix is similar to that of Scenario B. In contrast, higher gas prices encourage a shift towards renewables and storage, albeit at a higher capital cost and higher total system cost.

Adjustments to carbon tax levels are expected to shift new capacity investments from fossil fuel to renewable energy generation. The increased carbon tax level tested in Sensitivity 14 is still not high enough to cause CO_2 emissions to drop significantly below the 3.0 Gt budget constraint.

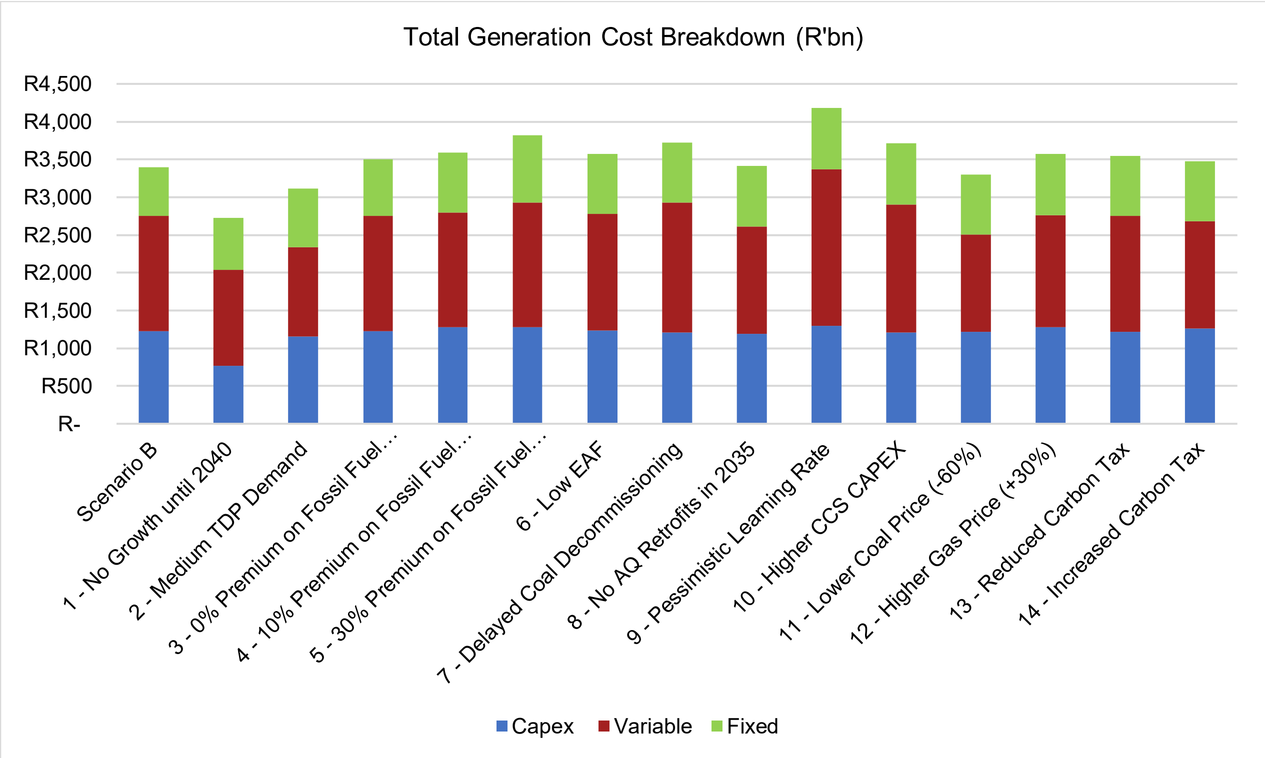


Figure 44: Total Generation Cost Breakdown per Sensitivity (R'bn, discounted)

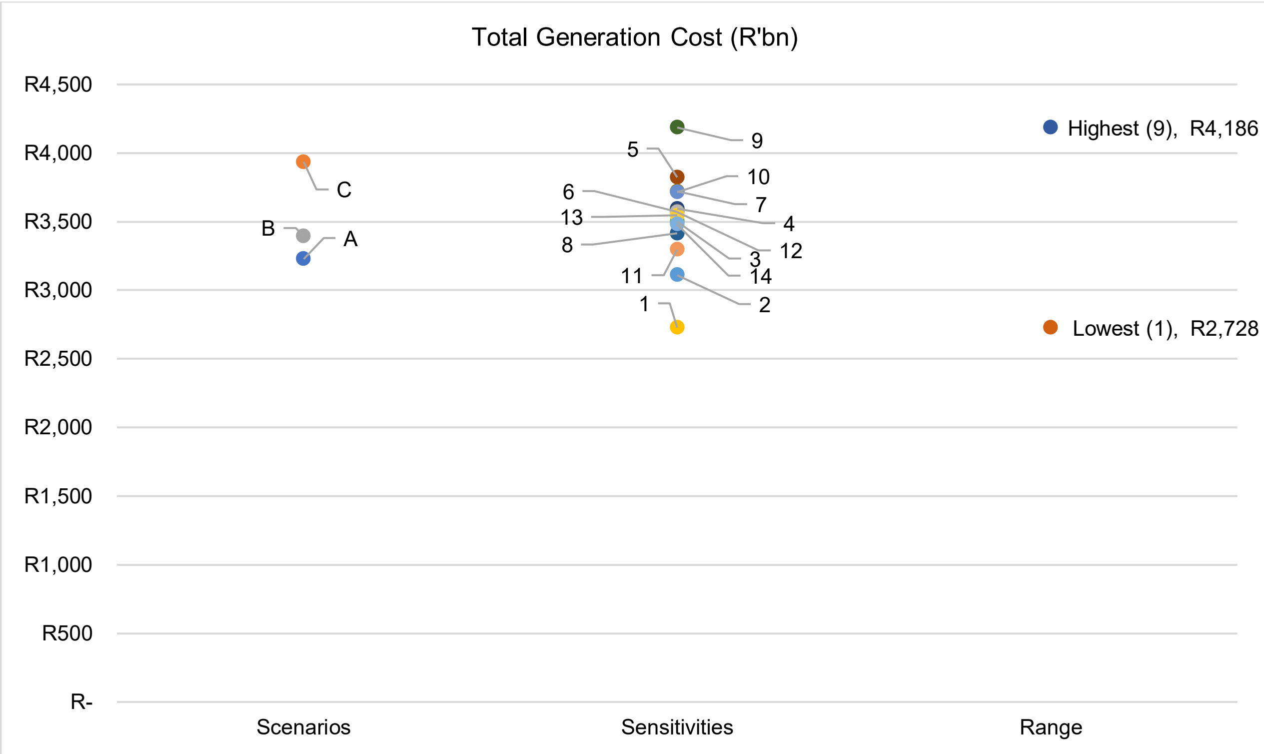


Figure 45: Total Generation Cost for All Sensitivities and Scenarios (R'bn, discounted)

Table 17: Sensitivities Generation Capacity Summary (cumulative operating by 2050)

Sensitivity	Description	Generation Capacity in GW by 2050							Notes
		Solar	Wind	BESS	Coal	CCS	Gas	Nuclear	
-	Scenario B (Market Forces)	64	33	33	0	10	27	2	Base case
1	No Growth until 2040	-27	-17	-15	0	0	-2	0	Theoretical case to determine the capital cost required to replace decommissioned coal fleet by 2040, keeping demand the same to 2040
2	Medium TDP Demand	-3	-1	-2	0	0	-2	0	Less generation capacity is needed due to less demand to supply
3	0% Premium on Fossil Fuel Generation Technologies	-1	-1	0	0	0	2	0	New Fossil Fuel technologies have a lower capex (as proxy for lower cost of capital). More gas capacity built and VRE capacity is reduced.
4	10% Premium on Fossil Fuel Generation Technologies	1	2	0	0	0	-4	0	New Fossil Fuel technologies have a higher capex (as proxy for higher cost of capital). Gas is reduced and replaced by more VRE.
5	30% Premium on Fossil Fuel Generation Technologies	4	3	6	1	-1	-15	4	When the capex premium (as proxy for higher cost of capital) is increased to 30% for fossil fuel technologies, the model opts to build new nuclear.
6	Low EAF	-3	2	0	0	0	1	0	More gas is dispatched around 2030 to compensate for the lower EAF. Beyond 2030, the generation mix,

Sensitivity	Description	Generation Capacity in GW by 2050							Notes
		Solar	Wind	BESS	Coal	CCS	Gas	Nuclear	
									and capacity build is similar to Scenario B.
7	Delayed Coal Decommissioning	-3	-1	0	1	0	-1	0	Less new VRE capacity is built as the coal fleet is forced to remain online until the end of its extended life. Higher contribution from VRE and BESS and less from gas in later years to keep CO_2 emissions within 3.0 Gt budget.
8	No AQ Retrofits in 2035	-3	2	0	0	0	0	0	Similar result to Sensitivity 7, except costs are lower since AQ retrofits are not deployed.
9	Pessimistic Learning Rate	-18	-8	-6	0	0	6	0	It is relatively more expensive to build renewables, so the model builds less new VRE and BESS capacity and replaces this with more gas generation.
10	Higher CCS CAPEX	14	6	7	0	-10	1	0	When cost of CCS is increased by 30% from the current expected cost level, it is no longer deployed, and the model builds more VRE and BESS to compensate.
11	Lower Coal Price (-60%)	0	1	0	0	0	-3	0	Coal plants remain online for longer and dispatch more between 2030 and 2040. By 2050, the capacity and energy mix is similar to Scenario B.

Sensitivity	Description	Generation Capacity in GW by 2050							Notes
		Solar	Wind	BESS	Coal	CCS	Gas	Nuclear	
12	Higher Gas Price (+30%)	2	2	3	0	0	-5	0	Increase in gas prices reduces new gas capacity and gas dispatch. More VRE and BESS capacity is built to compensate. Total costs increase.
13	Reduced Carbon Tax	-3	0	-1	0	0	4	0	AQ retrofits are deployed for more of the coal fleet and they remain online for longer.
14	Increased Carbon Tax	0	1	0	0	0	2	0	From 2035 to 2050, gas generation reduces and VRE and BESS contribute more of the energy mix. The total CO_2 emissions still hit the 3.0 Gt limit.

Table 18: Sensitivities Cost Comparison (R'bn, total 2025 to 2050, discounted 8% to 2024 real terms)

Sensitivity	Description	Capex	Variable	Fixed	Total Cost	Total Cost + CO_2 Tax
-	Scenario B (Market Forces)	R 1 229	R 1 520	R 646	R 3 395	R 3 741
1	No Growth until 2040	-R 459	-R 250	R 42	-R 667	-R 639
2	Medium TDP Demand	-R 73	-R 342	R 130	-R 285	-R 251
3	0% Premium on Fossil Fuel Generation Technologies	-R 2	R 7	R 100	R 105	R 117
4	10% Premium on Fossil Fuel Generation Technologies	R 53	-R 8	R 155	R 199	R 223
5	30% Premium on Fossil Fuel Generation Technologies	R 50	R 128	R 251	R 429	R 369
6	Low EAF	R 10	R 16	R 151	R 177	R 187
7	Delayed Coal Decommissioning	-R 23	R 199	R 150	R 327	R 335

Sensitivity	Description	Capex	Variable	Fixed	Total Cost	Total Cost + CO_2 Tax
8	No AQ Retrofits in 2035	-R 41	-R 93	R 154	R 21	R 33
9	Pessimistic Learning Rate	R 66	R 557	R 168	R 791	R 796
10	Higher CCS CAPEX	-R 24	R 180	R 164	R 320	R 346
11	Lower Coal Price (-60%)	-R 11	-R 237	R 149	-R 99	-R 118
12	Higher Gas Price (+30%)	R 51	-R 43	R 167	R 175	R 199
13	Reduced Carbon Tax	-R 8	R 13	R 147	R 152	-R 15
14	Increased Carbon Tax	R 34	-R 105	R 156	R 85	R 326

4.6 Results and Discussion

4.6.1 Expansion of Variable Renewable Energy (VRE)

In all scenarios and sensitivities, the largest component of new power generation capacity is the VRE technologies, comprising solar PV and wind. This occurs irrespective of the range or absence of CO_2 budget constraints, technology learning rates, the level of carbon tax, the coal and gas price, and level of Capex premium on fossil fuel technologies (as a proxy for the cost of capital), tested over the range of scenarios and sensitivities in this study.

This implies that under the full range of scenarios and sensitivities tested in this study, significantly increasing the quantum of modern and sustainable energy in South Africa's energy mix via a significant expansion of VRE capacity does not require a trade-off with cost; instead, it is the least-cost approach.

4.6.1.1 Time Horizon: 2025 to 2030

Currently, renewable energy contributes close to 10% of South Africa's total energy mix (Centre for Renewable and Sustainable Energy Studies (CRSES), 2024). The IRP 2019 (as the last accepted IRP) sets a measurable target of an increase in renewable energy from the current state (in 2019) of approximately 10% to around 40% by 2030, and reduce the share of fossil fuels from 80% to 50% out of a projected installed capacity of 78 GW, while excluding the distributed capacity from the total (EnergyGroup, 2024). This will be achieved through the additional capacity of 14 GW of wind and 6 GW of solar PV, excluding previously contracted or committed projects (DMRE, 2019).

The Draft IRP 2023 forecasts the development of additional new capacity to bring the total contribution of VRE by 2030 to 26 GW, consisting of 11 GW of distributed solar PV, 6 GW of solar PV, 8 GW of wind, and 600 MW of concentrated solar power (CSP) (DMRE, 2024a). As an extension of the Draft IRP 2023, the DMRE released a Draft Integrated Resource Plan Stakeholder Workshop document in November 2024. This document expresses the intention to incorporate more renewable energy sources, particularly up to 2030. The Draft IRP 2024 Stakeholder Workshops document states that VRE will contribute an additional 27.4 GW to the national capacity by 2030. This translates to 11.3 GW of rooftop solar PV, 7.8 GW of utility scale solar PV, and 7.2 GW of wind by 2030. The total build-out of VRE by 2050, as per the Draft IRP 2024 document, also calls for the aggressive development of renewable energy, potentially contributing 127 GW to the national total by 2050. This would be due to adding 24.3 GW of solar PV and 76.4 GW of wind energy to the grid between 2031 and 2050 (DMRE, 2024b).

The 2024 South African Renewable Energy Grid Survey provides an overview of renewable energy projects that are still in development and will require grid access by 2032 (Eskom, 2024c). This survey, co-authored by the South African Photovoltaic Industry Association (SAPVIA), Eskom, and the South African Wind Energy Association (SAWEA), relied on respondents providing information about their projects and their projects' development stage. Projects are categorized as type A, B, and C according to several criteria.

Type A projects are at an advanced stage of development, have attained environmental approval, and should reach commercial operation date (COD) within three years if granted grid connection by Eskom. Type B projects are still under development, having submitted draft EIAs and with feasibility studies in advanced stages or completed. A project off-take is in progress, but has not yet been finalized. Type B projects would be able to reach COD within five years if granted a grid connection immediately. Type C projects are still at an early stage of development and are still in a feasibility or prefeasibility stage. These projects are expected to reach COD within five to seven years. Table 19 shows the total capacity of solar PV and wind projects by the year 2030 and distinguishes between type A, B, and C projects according to the South African Renewable Energy Grid Survey.

Table 19: Total Capacity (GW) of Solar PV and Wind Projects from Eskom Grid Survey by 2030

Solar PV			Wind		
Type A	**Type B**	**Type C**	**Type A**	**Type B**	**Type C**
30.3	14.6	9.9	12.0	4.7	9.8
Total: 54.8			Total: 26.5		

Source: 2024 South African Renewable Energy Grid Survey (Eskom, 2024c).

Meridian Economics released its independent Review of the IRP 2023 in March 2024 (Meridian Economics, 2024). The study presents a range of scenarios reflecting different assumptions for technology learning rates, coal decommissioning timelines, and renewable energy build constraints. In their Base Case, 'RE Build' scenario, total VRE capacity reaches 29 GW by 2030, reflecting a more conservative renewable energy rollout aligned with current policy trajectories. In the 'Likely RE Learning' scenario, where faster technology cost reductions are assumed, total VRE capacity increases to 32 GW by 2030. In the most ambitious scenario ('Coal Off by 2040'), where coal is fully phased out by 2040, total VRE capacity increases to 36 GW by 2030. These results provide a useful benchmark for comparing the renewable energy build trajectories in this study, which in several scenarios reflect higher VRE capacities driven by emissions constraints, optimistic technology learning assumptions, and faster coal phase-out policies.

Table 20 provides a comparison of the total VRE capacities projected to be installed by 2030 from the IRP 2019, Draft IRP 2023, Draft IRP 2024, 2024 South African Renewable Energy Grid Survey (Eskom, 2024c), and this study.

Table 20: Comparison of VRE Capacity (GW units) by 2030

Energy Source	IRP 2019	Draft IRP 2023	Draft IRP 2024	Meridian Economics[18]	Grid Survey[19] (Type A+B)	This Study
Distributed	4	11	Included in PV	Included in PV	-	Included in PV
Wind	18	8	7	CO2040: 12 LRL: 9 BC: 8	17	A: 18 B: 11 C: 10
Solar PV	8	6	19	CO2040: 24 LRL: 23 BC: 21	45	A: 31 B: 21 C: 23
Concentrated Solar Power (CSP)	0.6	0.6	-	0.6	-	0.6
Total	31	26	26	CO2040: 36 LRL: 32 BC: 29	62	A: 49 B: 32 C: 33

Sources: DMRE (2019, 2024a, 2024b), Meridian Economics (2024), and Eskom (2024c).

Scenario A from this study projects a total VRE capacity that is 22 GW greater than that projected in the Draft IRP 2024. Scenario A adopts more optimistic technology learning rates than the Draft IRP 2024 and shuts down more of the existing coal fleet earlier, and achieves lower CO_2 emissions. The Draft IRP 2024 and the three scenarios selected from the Review of the IRP 2023 by Meridian Economics (2024) envisage a similar level of VRE capacity as scenarios B and C from this study.

Notably, the 62 GW of the types A and B projects that were identified in the 2024 South African Renewable Energy Grid Survey exceeded the total VRE capacity in Scenario A (49 GW) by a comfortable margin. These projects represent a credible pipeline of near-term build potential, with Type A projects expected to reach commercial operation within three years and Type B projects within five years, provided immediate grid access is granted. This comparison suggests that Scenario A aligns well with existing market interest and development activity, and that its build-out targets are feasible if proactive grid planning and timely connection approvals are implemented.

[18] *The following abbreviations apply to the Meridian Economics scenarios – BC: Base Case RE Build; LRL: Likely RE Learning; CO2040: Coal Off by 2040.*
[19] *Type A projects are at an advanced development level and have attained environmental approval and should reach commercial operation date (COD) within 3 years if granted grid connection by Eskom. Type B projects are still under development and have draft EIA submitted and feasibility studies are in advanced stages or completed. A project off-taker or intended off-taker is not yet finalised but in progress. These projects would be able to reach COD within five years if granted grid connection immediately.*

4.6.1.2 Time Horizon: 2031 to 2050

In general, there is greater uncertainty associated with forecasts that extend up to 2050. The Draft IRP 2023 and Draft IRP 2024 both provide projections for 2031 to 2050 (referred to as Horizon 2) under various scenarios. The Draft IRP 2024 Reference Case scenario analyses the power system based on existing and planned policies and is compared to the results from this study. Key assumptions in this scenario include a 50-year lifetime for Eskom’s coal plants post-2030, 6 GW gas generation as determined by NERSA, moderate annual electricity demand growth of 2.3%, continued operation of coal plants reaching 50 years by 2030, a 20-year lifetime extension for Koeberg, coal plant performance reaching an EAF of 68% by 2030, incorporation of all private sector committed generation capacity, and rooftop PV penetration of 900 MW per annum until 2035.

The Review of the IRP 2023 report by Meridian Economics (2024) criticises several cost assumptions employed in the Draft IRP 2023, particularly for wind, solar PV, CSP, and battery storage, which are significantly higher than actual market pricing as reported by the REIPPP Programme and other reference data. Additionally, the Draft IRP 2023 does not account for future technological advancements and the potential for inflated costs associated with new technologies compared to mature ones, such as coal, nuclear, and gas. The presentation of scenarios in the IRP does not provide costing for AQ retrofits such as flue gas desulphurization (FGD) or CCS. Meridian Economics (2024) recommends significant revisions to the IRP 2023 to improve alignment with South Africa's energy transition goals and economic reality, emphasising the need for a transparent and inclusive stakeholder engagement process. The analysis concludes that the plan is unrealistically constrained, resulting in overpriced renewables that facilitate a gas-heavy energy future, which conflicts with SDG 7.2 (Meridian Economics, 2024). The independent assessment of the IRP by Meridian Economics also establishes various scenarios, of which three have been selected for further comparison.

Table 21 provides a breakdown of the total capacity that is expected to be online by 2050, as per the Draft IRP 2024, Meridian Economics Review of the IRP 2023, and this study.

Table 21: Comparison of VRE Capacity (GW units) by 2050

Energy Source	Draft IRP 2024	Meridian Economics[20]	This Study
Distributed	Included in PV	Included in PV	Included in PV
Wind	84	CO2040: 85 LRL: 57 BC: 64	A: 48 B: 33 C: 32
PV	43	CO2040: 64 LRL: 75 BC: 51	A: 99 B: 64 C: 52
Total	127	CO2040: 149 LRL: 172 BC: 115	A: 147 B: 97 C: 84

Sources: DMRE (2024b) and Meridian Economics (2024).

A comparison of VRE capacity projections across this study, the Draft IRP 2024, and Meridian Economics scenarios, summarised in Table 21, shows both broad similarities and notable differences in terms of total capacity and the technology split between wind and solar PV.

A key point of alignment across all modelling exercises is that VRE, which consists of wind and solar PV, will dominate new-build capacity by 2050. All scenarios agree that the energy system of the future will be heavily reliant on renewables, with VRE forming the largest share of total installed capacity by 2050.

Further, the total VRE capacity projected in this study (ranging from 84 to 147 GW across scenarios A, B, and C) falls within the broader range defined by Meridian Economics' modelling outcomes (115 to 172 GW) and the Draft IRP 2024 projection (127 GW).

In this study, all three scenarios result in a more solar PV intensive system relative to wind, particularly in Scenario A, which sees PV capacity reach 99 GW by 2050, compared to wind capacity reaching 48 GW. Even in the more conservative scenarios B and C, PV capacity exceeds wind capacity, albeit at lower absolute levels. This difference is largely driven by assumptions of technology learning rates, where lower future PV costs incentivise a greater build-out of solar relative to wind. Additionally, operational assumptions further support a PV intensive build strategy in our scenarios, particularly regarding the role of storage technologies in shifting solar generation.

The differences in wind versus solar PV build between models also reflect divergent modelling philosophies and assumptions regarding system operation, resource availability, and deployment

[20] *The following abbreviations apply to the Meridian Economics scenarios – BC: Base Case RE Build; LRL: Likely RE Learning; CO2040: Coal Off by 2040*

constraints. For example, scenarios from Meridian Economics that favoured higher wind capacity may reflect a different treatment of wind resource availability and spatial-temporal variability in wind profiles across the country.

Despite these differences, all models indicated a significant expansion of both wind and solar PV capacity over the next three decades. The exact mix between wind and solar PV is highly sensitive to assumptions regarding future technology costs, the operational role of storage, system balancing requirements, and the treatment of resource profiles in the modelling frameworks.

Table 22 below provides a comparison of the estimated VRE build rates required by 2030 and 2050 from a range of sources. Scenario A broadly aligns with the upper end of the range from other sources, and results in the highest rate of new VRE capacity from this study. Scenarios B and C are comfortably within the range estimated from other sources.

Table 22: Estimates of Annual VRE Build Rates

Institution	VRE to be procured annually (GW units)	Timeline
Eskom	4–5	2023–2030
Department of Public Works and Infrastructure (DPWI)	5	2023–2050
Meridian Economics	6	2023–2030
PCC	6–8	5 years
This Study	A: 7 B: 3 C: 3	2025–2030
	A: 5 B: 3 C: 3	2025–2050

Source: Eskom, 2022; DPWI: NIP, 2022; Roff et al., 2023; PCC, 2023a

4.6.2 Supporting a High Penetration of VRE

To support a growing proportion of VRE in the energy mix, the variable production balance must be considered so that supply and demand are matched to deliver a reliable and secure supply, as well as power generation, collection, and transmission via the grid to the load.

4.6.2.1 Balancing VRE production

Introducing variable output generation technologies, such as solar PV and wind, requires the careful balancing of dispatchable generation technologies to ensure a reliable and secure supply, as electricity supply and demand must always remain exactly balanced. As the penetration of variable renewable generation capacity increases, the capability of dispatchable generation to balance the increased variability must also increase.

From a practical perspective, not all dispatchable generation technologies are well-suited to providing a balancing function. Coal, nuclear, and to a lesser extent CCGT power plants, are only capable of ramping their output up and down at relatively slow rates due to the limitations of their steam cycle designs. Furthermore, the number of starts and stops for which these types of power plants are designed is limited compared to other technologies. Increasing the number of starts and stops will decrease the remaining expected life of the components. BESS and PHS schemes are well-suited to providing shorter-term (seconds up to several hours) balancing support to the grid, while OCGT power plants are well-suited to providing longer-term (minutes up to several days) balancing support.

This study applied an iterative approach between OSeMOSYS and FlexTool to determine the least-cost energy mix, which can balance supply and demand, based on the operational and performance characteristics of VRE and dispatchable technologies. All scenarios in this study were required to meet demand by no later than 2030. Interrogating the results from all scenarios confirms that there is no unserved energy (i.e., load shedding) from 2030 onwards.

Table 23 provides a comparison of dispatchable generation capacity (excluding coal and nuclear) by 2030 from the IRP 2019, Draft IRP 2023, Draft IRP 2024, Meridian Economics Review of the IRP 2023, and this study.

Table 23: Comparison of Dispatchable Generation Capacity (GW units) (excluding coal and nuclear) by 2030

Energy Source	IRP 2019	Draft IRP 2023	Draft IRP 2024	Meridian Economics[21]	This Study
Gas	9	12	6	CO2040: 8 LRL: 8 BC: 8	A: 9 B: 7 C: 5
BESS	-	4	4	CO2040: 6 LRL: 6 BC: 6	A: 11 B: 2 C: 2
Pumped Storage	5	3	-	-	A: 3 B: 3 C: 3
Total	14	19	10	CO2040: 14 LRL: 14 BC: 14	A: 23 B: 12 C: 10

Sources: DMRE (2019, 2024a, 2024b) and Meridian Economics (2024).

Compared to the other scenarios, Scenario A from this study involves the most accelerated expansion of VRE and decommissioning of existing coal plants, resulting in the largest capacity of gas and BESS by 2030. When compared to the IRP 2023, IRP 2024, and the independent analysis of the draft IRP 2023 by Meridian Economics, the gas capacity in Scenario A is relatively aligned. However, the new BESS capacity is substantially larger in Scenario A, due to Scenario A's larger VRE capacity, which needs to be supported by 2030.

Scenarios B and C have a smaller quantum of VRE capacity by 2030, hence requiring a smaller gas and BESS capacity to support this. The capacity of gas and BESS envisaged by IRP 2023, IRP 2024, and Meridian Economics both surpass the capacities required for scenarios B and C in this study.

Table 24 provides a comparison of dispatchable generation capacity (excluding coal and nuclear) by 2050 from the Draft IRP 2024, Review of the IRP 2023 by Meridian Economics (2024), and this study.

[21] The following abbreviations apply to the Meridian Economics scenarios – BC: Base Case RE Build; LRL: Likely RE Learning; CO2040: Coal Off by 2040

Table 24: Comparison of Dispatchable Generation Capacity (GW units) (excluding coal, nuclear) by 2050

Energy Source	Draft IRP 2024	Meridian Economics[22]	This Study
Gas	31	CO2040: 45 LRL: 31 BC: 43	A: 23 B: 26 C: 29
BESS	9	CO2040: 40 LRL: 54 BC: 24	A: 53 B: 33 C: 25
Pumped Storage	-	-	A: 5 B: 5 C: 5
Total	40	CO2040: 85 LRL: 85 BC: 67	A: 81 B: 64 C: 59

Sources: DMRE (2024b) and Meridian Economics (2024).

In general, the energy model developed for this study projects less gas capacity compared to the Meridian and IRP models. Sensitivity Case 9 (pessimistic renewable energy learning rates) and Sensitivity Case 13 (reduced carbon tax) from this study result in 6 and 4 GW of additional gas capacity by 2050, respectively. When considering the combination of gas and BESS technologies, Scenario A from this study produces a similar result to Meridian's 'Likely RE Learning' and 'Coal Off by 2040' scenarios, while Scenario B produces a similar result to Meridian's base case, the 'RE Build' scenario.

Note that Scenario A has the largest capacity of VRE and the lowest CO_2 emissions, which results in the lowest gas capacity and highest BESS capacity by 2050. In contrast, Scenario C has the smallest capacity of VRE and the highest CO_2 emissions, resulting in the highest gas capacity and the lowest BESS capacity by 2050. This suggests that the least-cost approach to achieving lower CO_2 emissions is to shift from gas to BESS (charged by VRE). However, both gas and BESS technologies are still required.

4.6.2.2 Collecting and transporting renewable energy production

The identified grid requirement aligns with the TDP 2024, which highlights a demand for transmission expansion and strengthening to collect power generated in areas with high renewable energy resources. The TDP proposes the development of the three main 765 kV corridors collecting power from the

[22] *The following abbreviations apply to the Meridian Economics scenarios – BC: Base Case RE Build; LRL: Likely RE Learning; CO2040: Coal Off by 2040.*

Northern Cape (Western), Eastern Cape (Eastern), and the Western Cape via Hydra Central (Central) corridors. Similarly, this study identifies these three main corridors as key to unlocking more affordable VRE generation (see Section 4.4.3). In addition to the 765 kV and 400 kV lines, the TDP 2024 also proposes that approximately 210 transformers, totalling 133 000 MVA of transformation capacity, are necessary to integrate distributed renewable energy projects into the transmission grid.

Integrating VRE projects with inverter-based technology can be challenging, especially when there is a high energy generation quantum in an area without a short circuit contribution, such as the Northern Cape. NTCSA has proposed eight synchronous condensers in the Western, Eastern, and Northern Cape provinces to address the inertia loss from retiring coal plants and to increase the efficacy of the grid to integrate inverter-based technology with VRE projects. These synchronous condensers will be vital for integrating the wind and solar PV capacities proposed in this study.

The TDP 2024 proposes the installation of 14 494 km of transmission lines and 210 transformers, thereby adding 133 GVA of capacity. NTCSA has identified the supply chain challenges associated with identifying local engineering, procurement, and construction (EPC) partners capable of executing this transmission build, which will be accelerated compared to that of the previous decade. To address this, NTCSA established EPC panels through a prequalification process, enabling a pool of local companies to be eligible for future work on transmission line construction. In parallel, NTCSA launched an incubation programme aimed at developing local high-voltage line construction capacity, with two contractors having already completed the programme. These mitigation measures by NTCSA are critical to de-risking the implementation of the grid expansion and strengthening timeously to facilitate the generation mix and associated capacities proposed in scenarios A, B, and C.

In addition, the South African Government's Independent Transmission Projects (ITP) initiative is a major programme aimed at rapidly expanding and modernizing the country’s electricity transmission network by partnering with private sector investors. The Government has launched a pilot phase to construct 1 164 km of new lines, aimed at unlocking an additional 3 222 MW of grid capacity. The ITP enables independent transmission providers to finance, design, build, and operate transmission infrastructure, with the assets ultimately transferring to state ownership under the NTCSA. This approach is intended to overcome public funding constraints and address critical grid bottlenecks (Pinsent Masons, 2025).

4.6.3 Role of the Existing Coal Fleet and Nuclear in the Energy Mix

Eskom plans to close seven of the current fifteen coal plants by 2030, as well as two more by 2035. As coal plants are decommissioned, an additional 57 GW of generation capacity and 10 GW of storage capacity will be necessary to address the prevailing energy security challenges (Eskom, 2022). A significant share of this capacity has already been identified in the 2024 South African Renewable Energy Grid Survey (see Section 4.6.1.1), where Type A projects, which are those at an advanced stage of development and expected to reach commercial operation within three years, collectively reflect substantial near-term delivery potential if granted timely grid access.

4.6.3.1 Impact of AQ retrofits on decommissioning timelines

This study employed decommissioning deadlines for the Eskom fleet, allowing the model to decide on a plant-by-plant basis whether to continue operating up until its decommissioning deadline or to cease operations earlier. The decision is based on least-cost optimization as well as any additional constraints in the model, such as CO_2 emissions limits. AQ retrofits were applied as a mandatory requirement in 2030 and 2035 for scenarios A and B, respectively (no mandatory requirement for Scenario C). For scenarios A and B, the model would determine whether to incur the cost associated with AQ compliance and allow the plant to continue operating or cease operations. While the cost of AQ retrofits is approximate due to limited available information (see Section 4.3.3), the timing of AQ compliance appears to impact the decommissioning of the coal fleet significantly.

Scenario A, which mandates AQ compliance by 2030, results in the decommissioning of 23 GW of the coal fleet by 2030, with 14 GW remaining online. The plants that remain online beyond 2030 (Medupi, Kusile, Majuba, Kendal, Lethabo, and Matimba) all have a longer remaining life than the plants which are decommissioned. A similar outcome is observed in Scenario B, which mandates AQ compliance by 2035, and results in 24 GW of the coal fleet being decommissioned by 2035, with 10 GW remaining online (Medupi, Kusile, and Majuba). Scenario C, which never mandates AQ compliance, has 28 GW of coal still operating in 2035, and only sees a significant reduction in coal generation after 2040.

Sensitivity Case 8 (No AQ retrofits in 2035) is applied to Scenario B; there is no mandatory requirement for AQ retrofits on the existing coal fleet. In this case, the model shows more coal plants operational from 2035 to 2045 (from 16 to 11 GW between 2035 and 2045), compared to Scenario B. This confirms that the cost of AQ retrofits drives the decommissioning of plants with shorter remaining lifetimes.

For Sensitivity Case 7 (Delayed Coal Decommissioning), the model allows coal plants to remain operational for longer periods, which effectively defers their planned decommissioning dates. Importantly, this does not account for the potential cost implications of plant life extension (such as refurbishment or maintenance costs) and should therefore be interpreted as a technical outcome. Plants like Kendal, Tutuka, Matimba, and Lethabo will continue to operate until 2040 after receiving AQ retrofits in 2035. Kendal never gets decommissioned and remains part of the energy mix in 2050.

Across the IRP 2024 and Meridian modelling exercises, the assumed coal decommissioning trajectories are broadly aligned in the near to medium term, with coal capacity reducing from approximately 39.6 GW in 2025 to around 30.7–32.4 GW by 2030. The key differences between the scenarios emerge post-

2030, where alternative policy or emissions constraint assumptions result in divergent speeds and extents of coal plant phase-outs.

In the IRP 2024 Base Case and Meridian Reference scenarios, coal capacity declines steadily to 21.8 GW by 2040 and further to 10.6 GW by 2050. However, in Meridian's Net Zero scenario and their 9 Gt emissions budget scenario, the pace of decommissioning accelerates substantially, reaching 16.3 GW by 2040 and a complete phase-out (0 GW) by 2050. By contrast, the IRP 2024 includes a specific Delayed Decommissioning scenario, where coal capacity remains materially higher for longer, declining to 29.8 GW by 2040 and 19.8 GW by 2050.

In this study, coal decommissioning pathways vary across scenarios depending on the emissions constraint and technology assumptions. Scenario A (2 Gt) reflects the fastest phase-out of unabated coal, with capacity dropping to 14 GW by 2030 and further reducing to 9.9 GW by 2045. The residual 9.9 GW reflects retrofitted coal with CCS, which comes online from 2035. Scenario B (3 Gt) delays the coal phase-out relative to Scenario A, maintaining 34.4 GW by 2030, and only reducing to the CCS-retrofitted 9.9 GW by 2040. Scenario C (Unconstrained) features the slowest phase-out, broadly corresponding to the IRP 2024 Delayed Decommissioning scenario, with 28 GW of coal still online by 2035 and declining to 10.6 GW by 2050.

Table 25 provides a comparison of coal plant capacity for 2030, 2040, and 2050 from the Draft IRP 2024, Meridian Review of the IRP 2023, and this study.

Table 25: Comparison of Coal Capacity (GW units) from 2030, 2040, and 2050

Year	Draft IRP 2024[23]	Meridian[24]	This Study
2030	33	CO2040: 30 LRL: 32 BC: 32	A: 14 B: 34 C: 34
2040	19	CO2040: 0 LRL: 22 BC: 22	A: 14 (10 with CCS) B: 10 (with CCS) C: 15
2050	11	CO2040: 0 LRL: 11 BC: 11	A: 10 (with CCS) B: 10 (with CCS) C: 11

[23] *Coal capacity at each year was estimated from the 50-year life shutdown scenario as shown on the figure on page 11 of the Draft IRP 2024 (DMRE), 2024b*

[24] *The following abbreviations apply to the Meridian Economics scenarios – BC: Base Case RE Build; LRL: Likely RE Learning; CO2040: Coal Off by 2040.*

Sources: DMRE (2024b) and Meridian Economics (2024).

Compared to IRP 2024 and Meridian modelling, scenarios A and B fall within their coal capacity range, particularly in the 2025 to 2040 period. However, Scenario A reflects a more aggressive transition aligned with net-zero scenarios, while Scenario C aligns more closely with the delayed coal schedule of the IRP 2024.

4.6.3.2 Carbon capture and storage (CCS)

The energy model for this study included a technology option for CCS retrofits to existing coal power plants. Unlike the AQ compliance mandates, CCS was only provided as an option beyond a certain date. The model would decide whether to deploy CCS based on least-cost optimization and meeting constraints such as the CO_2 emissions budget.

The model opted to deploy CCS in scenarios A and B, but only for the Medupi, Kusile, and Majuba plants. These are the three coal plants with the longest remaining lifetimes. For Scenario A, CCS is deployed in 2035, and for Scenario B, in 2040.

The immense scale of CCS retrofitting required for these coal plants compared to the current scale of CCS deployment worldwide is clearly a risk factor. If CCS deployment continues to grow at a compound annual rate of 32% as it has since 2017 (which is likely optimistic), the CCS retrofit for these three power plants would still comprise 8% of the global installed CCS capacity.

Sensitivity Case 10 (Higher CCS Capex) involved increasing the Capex of CCS retrofits until the model no longer deploys CCS, as it is no longer the least-cost option. If the Capex of CCS is increased by 30% from the current Capex forecast, the model no longer deploys CCS, and all coal plants are decommissioned by 2045. To address demand, the model alternatively deploys an additional 14 GW of solar PV, 6 GW of wind, and 7 GW of BESS, which increases the total generation cost up to 2050 by approximately 9% (compared to Scenario B).

None of the IRP 2023, IRP 2024, or the Meridian Economic models (2024) deploy CCS. This is most likely due to these models using differing cost assumptions or technologies compared to the present study.

4.6.3.3 New nuclear capacity

New nuclear generation was made available as a technology option in all scenarios and sensitivity cases. None of the scenarios (A, B, or C) opted to deploy new nuclear generation capacity. Among the sensitivity cases, new nuclear is only deployed under Sensitivity Case 5 (30% Premium on Fossil Fuel Generation Technologies), which was specifically included to identify the approximate price point at which the model would select nuclear. This was achieved by applying a Capex premium factor on new fossil fuel technologies, including gas. When a 30% Capex premium is applied, the model opts to build 2 GW of new nuclear capacity in 2045 and another 2 GW in 2050.

Sensitivity Case 12 (Higher Gas Price: +30%) increases the gas price by 30% compared to Scenario B, but this did not result in new nuclear capacity. This study did not specifically test for the price point of gas at which the model would select to develop new nuclear capacity.

The Draft IRP 2024 Reference Case Build Plan (up to 2050) and all the scenarios and time horizons in the analysis by Meridian Economic (2024) do not feature new nuclear capacity. New nuclear capacity features in one scenario from the Draft IRP 2024, namely the Nuclear Scenario Build Plan, which assumes that no new gas capacity can be deployed after 2035.

In summary, unless gas is not available or if the Capex (or equivalent cost of capital) is 30% higher than current forecasts, new nuclear capacity is not considered to form part of the least-cost energy mix, even with stringent CO_2 emissions constraints.

4.6.4 Meeting the CO_2 Emissions Budgets

South Africa has set NDC targets to limit its annual GHG emissions to between 398 and 510 Mt CO_2e by 2025 and 350 and 420 Mt CO_2e by 2030 (RSA: NDC, 2021). The JET IP is aligned with the updated NDC emissions targets and indicates that a net-zero CO_2 goal will be achieved by 2050, along with an overall GHG emissions budget for the period from 2021 to 2050 of 7.8 to 8.5 $GtCO_2e$ (The Presidency, 2022). Modelling conducted by the UCT: ESRG for the World Bank Group’s Country Climate and Development Report (Marquard et al., 2021; World Bank, 2022) to apportion GHG emissions per sector provides a budget of approximately 2.5 $GtCO_2e$ for the power sector between 2023 and 2050, based on an economy-wide budget of 9 $GtCO_2e$ between 2021 and 2050.

Specifically relating to decarbonization and net-zero goals, Eskom expresses in the JET Fact Sheet #001 that net zero implies some residual emissions, which will be offset by carbon-absorbing technologies. Eskom adopts the view that these technologies will improve in the future; however, Eskom also recognises that the JET is part of the long-term strategy to shift towards financial sustainability and therefore hopes to achieve net-zero carbon emissions by 2050 (Eskom, 2021).

The three scenarios modelled for this study represent different intersections of local and global pathways as discussed in Section 3. Scenario A represents an alignment of strong local and global focus on green industrialization and reduction of CO_2 emissions. The result of Scenario A represents the least-cost energy mix to achieve 2.1 Gt CO_2 emissions over the period 2023 to 2050, based on the input assumptions applicable to that Scenario. Scenarios B and C are based on progressively less local and global focus on green industrialization and CO_2 emissions reduction and represent the least-cost energy mixes to achieve 3.1 and 4.5 Gt CO_2 emissions, respectively.

In 2050, Scenario A produces the lowest emissions with 8 Mt/a. Scenarios B and C result in 51 Mt/a and 129 Mt/a, respectively. The 8 Mt/a residual emissions in Scenario A arise primarily from gas-fired peaking capacity, which is used to support the integration of high levels of VRE. According to Roff et al. (2023), such an outcome aligns with credible net-zero pathways, where the carbon budget is strategically allocated to emissions from plants with flexible peaking capacity. These plants can later transition to green hydrogen or ammonia as fuel sources, enabling full decarbonization. Importantly, the cost impact of such residual emissions should be minimal, as peaking fuel costs comprise only a small fraction of total system costs at that point in the energy transition (Roff et al., 2023). Scenario A thus remains compatible with a net-zero trajectory for the power sector, provided that enabling conditions for clean fuel switching are developed in parallel.

Since Scenario A is based on optimistic assumptions relating to VRE and BESS technology learning rates and lower fuel prices amongst others (which are aligned with the local and global context of this scenario), it also achieves the lowest total system cost (i.e., total Capex and Opex for both generation and grid infrastructure, discounted to 2024 real terms), compared to scenarios B and C. This implies that there may not need to be a trade-off between cost and achieving South Africa's NDC and JET IP GHG emissions targets.

Achieving the Scenario A CO_2 emissions budget requires an accelerated shutdown of the existing coal fleet, with capacity dropping to 14 GW by 2030, i.e., only Medupi, Kusile, Majuba, Kendal, Lethabo, and Matimba remain online. From 2035, Medupi, Kusile, and Majuba must be retrofitted with CCS, and from 2045, Kendal, Lethabo, and Matimba are decommissioned. As discussed in Section 4.3.7, if CCS technology has not sufficiently matured by 2035, then Medupi, Kusile, and Majuba would also need to be decommissioned, additional VRE and BESS would be required to address the demand gap and maintain the CO_2 emissions budget.

Scenario B represents a more gradual transition away from coal, is based on less optimistic technology learning rate and fuel price assumptions (amongst others), but only achieves a 3.1 Gt CO_2 emissions budget, which may breach future NDC targets by exceeding the power sector's contribution towards the overall budget. The most optimum scenario may lie somewhere between scenarios A and B.

The energy sector's historical reliance on coal has created economic dependencies that are difficult to transition away from without significant social and economic disruption (Ledger, 2021). Transitioning away from coal to renewable energy sources to achieve this CO_2 emissions budget could lead to job losses in the coal sector and pose significant socio-economic challenges (Inglesi-Lotz, 2023; The Presidency, 2022; RSA: NDC, 2021). This can disproportionately affect low-income communities that are dependent on coal mining and related industries. The supplementary CGE model report will shed more light on this specific topic.

Countries that do not adhere to their NDCs under the Paris Agreement will affect other countries' decision-making around their investment into a country that does not have a modern technology mix relative to its fossil fuel generated electricity supply. This can also pose a challenge to achieving economic growth and maintaining economic competitiveness in the global market.

The transition to affordable, reliable, sustainable, and modern energy services is reliant on the learning rates of new power generation technologies being sufficiently high to reduce overall electricity tariffs. High energy costs, especially for low-income households, therefore, remain a significant barrier (World Bank, 2021). Women, particularly in low-income households, are disproportionately affected by high energy costs, the unaffordable renewable energy capital costs, coal community-related adversity, and limited access to modern energy services. This exacerbates existing social and economic inequalities, as women often bear the brunt of energy poverty, spending more time on unpaid domestic work and facing health risks from traditional cooking methods (Tandrayen-Ragoobur, 2024).

4.6.5 Funding the Transition

4.6.5.1 Quantum

The investment requirements determined for the various scenarios (in 2024 real terms) are summarised in Table 26.

Table 26: Investment Requirements (2025 to 2050) (R'bn, discounted 8% to 2024 real terms)

Scenario	Total Generation Capex	Total Generation Opex	Total Grid Capex	Total investment required	Average annual investment
Scenario A	1 651	1 552	383	3 586	138
Scenario B	1 229	2 166	262	3 657	141
Scenario C	1 446	2 490	231	4 166	160

Estimates for the energy infrastructure investment requirements from various leading institutions are represented in Table 27. While the values were obtained from several studies that investigated South African energy infrastructure needs, the studies covered different timeframes and development objectives.

Table 27: Estimates of Investment Needed to Transform South Africa's Energy Infrastructure Landscape from Various Sources

Source	Total investment required (R'bn)	Period (Range)	Average annual investment (R'bn)
Meridian: IRP 2023 Costs	3 800	2025–2050	152
Meridian: Base Case RE Build	3 721	2025–2050	149
Meridian: Likely RE Learning	3 642	2025–2050	146
Meridian: Coal off by 2040	3 922	2025–2050	157
JET IP	648	2023–2027	130
National Business Initiative (NBI)	2 840	2020–2050	95
Blended Finance Taskforce (BFT)	3 225	2022–2050	115
Eskom	1 119	2022–2035	86
World Economic Forum (WEF) Working Group	635	2024–2030	106
This Study: Scenario A	3 586	2025–2050	138
This Study: Scenario B	3 657	2025–2050	141
This Study: Scenario C	4 166	2025–2050	160

Sources (in order): Meridian Economics, 2024; The Presidency, 2022; National Business Initiative (NBI), 2022; Blended Finance Taskforce (BFT), 2022; Eskom, 2022; World Economic Forum (WEF), 2024a.

Given the various criteria and assumptions that were considered in each report, the rationale behind these values is:

- **Meridian Economics**: The Review of the IRP 2023 by Meridian Economics (2024), as discussed earlier in this report, includes similar modelling as was conducted for this study for several different scenarios. The three scenarios compared earlier in this report are included below for comparison (i.e., the base case 'RE Build', 'Likely RE Learning', and 'Coal off by 2040'). These scenarios are based on similar cost and performance parameters to those of this study. An additional scenario IRP 2023 Cost Assumptions is also included, which is a least-cost optimization based on the cost assumptions from the Draft IRP 2023. The total cost metrics provided in the table were estimated based on the limited cost metrics available in the report.

Finally, while the review considers grid constraints, it did not include grid costs. Therefore, the total costs presented for these scenarios are the total generation costs.

- **JET IP:** The JET IP establishes an investment target of R647.7 billion (USD 43.2 billion) specifically for the national electricity sector's infrastructure investment needs for five years from 2023–2027 (The Presidency, 2022). This includes coal plant decommissioning, transmission, distribution infrastructure, as well as new PV, wind, and batteries. The average annual investment to address the national electricity infrastructure requirement is therefore estimated to be R130 billion (USD 8.6 billion).
- **National Business Initiative (NBI):** The components of the transition that the NBI forecasts speak to include power generation, green hydrogen, adjustments to the petrochemical, mining, heavy manufacturing, transport, building and construction, as well as Agriculture, Forestry and Other Land Use (AFOLU) sectors. When isolating the power sector investment focus for the NBI study, which includes generation and grid expansion costs, this value amounts to R2 850 billion (USD 189.3 billion) over 30 years (2020–2050) and averages to R95 billion (USD 6.3 billion) annually.
- **Blended Finance Taskforce (BFT):** The Blended Finance Taskforce (BFT) expresses the following breakdown of their energy sector finance investment estimate: renewable energy build out (R1 875 billion: USD 125 billion), flexibility in relation to electricity storage and gas (R750 billion: USD 50 billion), transmission and distribution (R600 billion: USD 40 billion), green industrialization (amount not stated), early retirement of coal plants (R360 billion: USD 24 billion), climate justice outcomes (R150 billion: USD 10 billion). Isolating the purely infrastructure-related estimates, incorporating renewable energy (R1 875 billion: USD 125 billion), grid flexibility (R750 billion: USD 50 billion), and new transmission and distribution (R600 billion: USD 40 billion) equates to R3 225 billion (USD 215 billion) between 2022–2050. This results in an average investment estimate of R115 billion (USD 7.7 billion) annually for 2022–2050.
- **Eskom:** In the JET Fact Sheet #005, Eskom indicates that its total funding required by 2035 amounts to R1 200 billion (USD 80 billion) (Eskom, 2022). When isolating energy infrastructure costs, Eskom estimates that by 2035, R947 billion (USD 63.1 billion) will be necessary for additional generation and storage, R120 billion (USD 8 billion) for transmission infrastructure, and R52 billion (USD 3.5 billion) for strengthening the distribution network. This translates to R86 billion p.a. over the period 2022–2035.
- **WEF Working Group**: A WEF-Accenture-DBSA working group forecast that doubling renewable energy capacity, to align with Horizon 1 from Draft IRP 2023, would require an estimated investment of R245 billion (USD 16.3 billion) by 2030; however, generation capacity would be highly constrained by insufficient transmission on-take availability. The Working Group estimated the additional infrastructure investment required for transmission capacity at R390 billion (USD

26 billion). Collectively, the physical infrastructure electricity investment required to transform the South African energy sector by 2030 would amount to R635 billion (USD 42.33 billion) (WEF, 2024a). This sum equates to R106 billion (USD 7.05 billion) per annum until 2030.

The average investment requirements of the studies considered here range between R86 billion to R157 billion annually (considering different timeframes). The range from this study is R137 billion to R160 billion annually. Thus, the ranges overlap with the upper end of the range determined by this study, which extends slightly above the range from the comparison sources. At the upper end of the estimates from the comparison sources were the Meridian Economics scenarios (2024), which are the closest to this study in terms of underlying cost and performance assumptions and modelling approach, with the main difference being the addition of grid investments in this study.

Of the available external modelling exercises, this analysis is the most comparable to the Meridian Economics study in both scope and assumptions. Like this study, Meridian Economics explicitly evaluated the impacts of accelerated coal decommissioning, declining costs of renewable energy technology, and constraints on wind deployment. Meridian Economics’ ‘Likely RE Learning’ and ‘Coal off by 2040’ scenarios align closely with scenarios A and B of this study. Meridian Economics also selected pathways that internalize carbon pricing and emissions limits, producing results in terms of generation mix, emissions reduction, and system cost impacts.

The following sections contextualize the discussion on funding levels for each scenario, considering South Africa’s unique socio-economic circumstances and the general uncertainty associated with a 25-year timeline.

4.6.5.2 Variables

The following includes some of the key variables affecting investment requirements for electricity infrastructure from countries that have included renewables in their energy mix:

- **Upfront costs**: The variability around high initial investments (i.e., front-loading the development of a renewable energy market) potentially plays the largest role in determining the affiliate energy pricing. The upfront costs for renewable energy infrastructure, such as solar panels, wind turbines, and hydropower plants, can be high. However, these costs have been decreasing as technology advances and economies of scale are realized, hence scaling up green infrastructure to phase out fossil fuel infrastructure (World Bank, 2023a). Scenarios A, B, and C from this study considered a range of technology learning rates.
- **Government incentives:** Government incentives are a major factor in determining Capex and energy costs. Several countries offer incentives, subsidies, or tax breaks to encourage the adoption of renewable energy, including at the household level. These incentives can help offset the initial investment costs for both individuals and businesses (Qadir et al., 2021). Recently,

South Africa's policy landscape initiated several incentive opportunities to promote the uptake of renewable energy, including a solar panel subsidy for home installations (Viviers, 2023). Scenarios A, B, and C, as well as several sensitivity cases in this study, explore the impact of different carbon tax levels and different Capex premiums (as a proxy for the cost of capital).

- **Running costs:** Aside from Capex-related costs, operating and maintenance costs may define a sizeable portion of the subsequent energy pricing. The energy utility death spiral phenomenon describes how ageing and inadequate infrastructure relay costs back to energy consumers, as is the case with conventional coal-fired power stations (Athawale and Felder, 2022). Compared to fossil fuel power plants, renewable energy facilities have lower operating and maintenance costs; however, technical ability may still drive Opex in skill-scarce regions. Solar and wind farms require minimal ongoing expenses compared to fossil energy plants, once they are operational (Cantarero, 2020).
- **Fuel price variability:** Renewable energy sources such as sunlight and wind do not require fuel for generation. This can contribute to stable and predictable energy costs over the long term, as there is no exposure to fuel price volatility (Kumar and Jaipal, 2022). However, in South Africa, transmission and grid integration are expected to present a major source of pricing variability due to the limited capacity in many regions. The integration of renewable energy into existing power grids may require additional infrastructure investments, such as smart grids and energy storage systems, to handle intermittent energy generation from sources like wind and solar generated outside of the system controllers' landscape (Eskom, 2022). Furthermore, there is expected variability in legacy and future systems that may arise from climate change. This may directly impact power generation, which relies on the availability of wind and sunlight (Yalew et al., 2020). Scenarios A, B, and C, and two sensitivity cases from this study, considered a range of different fuel prices.
- **An enabling policy environment:** Supportive policies, such as feed-in tariffs (FiTs) or renewable portfolio standards (RPS), can impact cost distribution by providing financial incentives or requiring a certain percentage of energy to come from renewables (Kumar and Jaipal, 2022; Qadir et al., 2021). South Africa's energy and climate policy has been evolving over the past decades, and key policy instruments are discussed in subsequent sections of this report.

4.6.5.3 Barriers and trade-offs

Understanding the financial implications of the energy infrastructure scenarios is crucial for ensuring energy affordability for South Africa and its citizens. The large investments associated with expanding and maintaining electricity infrastructure present significant barriers. Limited public funds and the need for substantial private investment complicate efforts (Folly, 2021). Accessing financing remains a critical challenge, especially for renewable energy projects (World Bank, 2021).

Municipalities struggle to obtain outside funding for their energy infrastructure due to their lack of bankability and understanding of their cost of supply. This leaves them unable to justify the required tariff levels from NERSA for full recovery. Additionally, losing significant demand to private electricity producers in their distribution areas could reduce municipal finances and negatively impact subsidies for indigent users (Mawere and Andtshamano, 2024).

Low-emission development and economic decarbonization are essential to meet the developmental goals of the NDP (aiming to eliminate poverty and reduce inequality by 2030) and the NIP 2050, which links NDP objectives to actionable steps and intermediate outcomes. These efforts also align with the socio-economic imperatives of the SDGs and the decarbonization objectives of South Africa's NDCs under the Paris Agreement (UNFCCC, 2020).

Disparities in income and access to resources can limit poorer households' ability to afford modern energy services, exacerbated by the high upfront costs of renewable energy technologies (Ledger, 2021). Consequently, resource allocation trade-offs will influence the implementation of pathway- and scenario-specific options within South Africa's socio-economic environment during its energy transition.

With South Africa's history of regular load shedding, meeting electricity demand remains challenging. Eskom's debt and operational issues, as described in this report, indicate that its tariff revenue collections and budget allocations from the National Treasury will not significantly contribute to the new power generation, transmission, and distribution infrastructure required from 2025 to 2050. Therefore, limited financial and technical resources may need to be prioritized, potentially leading to trade-offs between different goals. For example, funding renewable energy projects might reduce resources available for other critical infrastructure projects (Inglesi-Lotz, 2023). This could mean continued investment in maintaining coal-fired power plants to meet demand or prioritizing electricity expenditure over road infrastructure maintenance.

Effective policies, international investment, and support are crucial for balancing these trade-offs and ensuring energy remains affordable and accessible while reducing emissions (RSA, 2021). The speed of technology learning rates will be a key determinant in reducing electricity costs to meet SDG 7 under limited resource availability.

4.6.5.4 Expected contribution from Eskom

The National Treasury released the 2023 Budget Review, which focused on debt relief for Eskom. The review states that a debt-relief arrangement is being formulated to cover R254 billion (USD 16.9 billion) in Eskom debt. The debt relief covers approximately R168 billion (USD 11.2 billion) in capital and R86 billion (USD 5.7 billion) in interest, over the next three years, with strict conditions. One condition for the bailout is that Eskom’s Capex is restricted to transmission and distribution development (National Treasury, 2023).

Initiatives to attract private sector investment through ITPs can enhance the efficiency and speed of implementation, while collaboration with government and stakeholders to develop funding models and regulatory frameworks ensures the financial sustainability of transmission projects (Eskom-NTCSA, 2024a; Eskom-NTCSA, 2024b).

The JET IP emphasises upgrading transmission and distribution networks to accommodate the renewable energy generated by the private sector, ensuring energy security and decarbonization (The Presidency, 2023). The TDP’s alignment with the Draft IRP 2024 also emphasises the need to address grid congestion and enable more on-take regions for renewable energy connectivity (Eskom-NTCSA, 2024a). The TDP 2024 expresses the installation of 14 494 km of transmission lines and 210 transformers, thereby adding 133 GVA of capacity, which will significantly boost the grid's ability to handle increased loads and integrate new power generation sources. The previous TDP 2022 stated that 53 GW of new power generation capacity, from all technologies, will need to be integrated by 2034. This was increased to 56 GW by 2034 in TDP 2024 (Eskom-NTCSA, 2024a).

Installing synchronous condensers at seven sites and additional transformers at existing substation sites will improve system stability and reliability amidst the large-scale penetration of renewable energy and the planned decommissioning of Eskom’s coal-fired power plants (Eskom-NTCSA, 2024a).

With a total estimated capital of R112.5 billion from FY25 to FY29 (annual average of R23 billion), including R85.6 billion for capacity expansion, TDP 2024 seeks to address current network constraints and support future demand growth, while also generating new jobs. The estimated cost of transmission infrastructure required by 2035, as per Eskom’s JET fact sheet five was R120 billion (annual average of R10 billion) (Eskom, 2022). In addition, Eskom’s JET Fact Sheet #5 estimated that upgrading and bolstering the distribution network would amount to around R52 billion by 2035 (annual average of R4 billion). Estimates of the total funding required for the transmission and distribution (collector networks only) over the period 2025 to 2050 from this study range from R231 billion (Scenario C, annual average of R9 billion) to R383 billion (Scenario A, annual average of R15 billion).

4.7 Conclusion

The three scenarios modelled for this study represent different intersections of local and global pathways. Scenario A represents an alignment of strong local and global focus on green industrialization and reducing CO_2 emissions. Scenarios B and C are based on progressively less strong local and global focuses on green industrialization and reducing CO_2 emissions. Model input assumptions vary across the scenarios, based on the external context for each specific scenario.

In all scenarios, the largest component of new power generation capacity consists of VRE technologies, i.e., solar PV and wind, that are primarily supported by new BESS and gas generation capacity. The scale and expansion rate of solar PV, wind, BESS, and gas capacity vary between scenarios, driven by changes in input assumptions, such as technology learning rates, fuel prices, and carbon tax, and model constraints, such as the CO_2 emissions budget and the mandatory requirement for AQ compliance of the coal fleet. All scenarios achieve a secure and reliable supply of electricity, with no load shedding forecast beyond 2030, provided the coal fleet meets the forecasted availability levels specified in Section 4.3.3.

Scenario A, based on its optimistic technology learning rates, lower fuel prices, higher carbon tax, and more stringent requirements for CO_2 emissions and AQ compliance (amongst others), results in the largest and most accelerated transition away from coal generation towards renewable energy, BESS, gas, and CCS. While the scale and rate of new capacity construction is the highest in Scenario A, the rate (GW constructed per annum) is similar to estimates from other sources (Eskom, 2022; DPWI, 2022; Meridian Economics, 2024; PCC, 2023a) and the quantum of new solar PV and wind capacity required by 2030 is less than the current pipeline of projects captured in the Renewable Energy Grid Survey 2024 (Eskom, 2024c). Despite the optimistic technology learning rates, Scenario A requires the largest up-front capital investment for new power generation capacity and grid capacity to collect and transport the large quantity of renewables, when comparing the three scenarios based on costs discounted to 2024. However, the total investment requirement in Scenario A is the lowest amongst the three scenarios due to the reduced requirement for fossil fuel, as renewable energy contributes the largest portion of the energy mix, and the lower fuel prices are a relevant input assumption in this scenario. Furthermore, Scenario A achieves the lowest CO_2 emissions.

Scenario A is not without its challenges and trade-offs. The large Capex investment requirement versus the available funding (see sections 5 and 6), the economic impact of decommissioning the coal fleet versus the economic benefit of a transition to renewables (to be assessed further as part of the CGE modelling), the technical capacity of the electricity industry to construct the required infrastructure at the required rate, and the local policy mechanisms required to enable key underlying assumptions (such as technology costs, carbon tax levels, AQ compliance deadlines, and fuel prices) must all be considered. The influence of external or global conditions, which also impact key assumptions such as fuel prices, technology learning rates, and technology readiness (in the case of CCS), must be considered, as well as global commitments and policies relating to CO_2 emissions reduction.

Scenarios B and C represent the least-cost approach to achieving a secure and reliable electricity supply in an environment where the local and global focus shifts further away from climate sustainability than Scenario A. While Scenario B represents the least-cost approach to achieve a 3.1 Gt CO_2 emissions budget limit, Scenario C represents the least-cost approach with no CO_2 emissions budget limit (resulting in 4.5 Gt CO_2 emissions).

Like Scenario A, scenarios B and C also result in a transition away from coal and towards a new energy mix comprised primarily of solar PV, wind, BESS, and gas. However, the transition occurs more gradually and less extensively than in Scenario A, with an overall lower capacity of new power generation, storage, and grid infrastructure required by 2030, 2040, and 2050. Scenarios B and C both emit 181 Mt/a CO_2 emissions in 2030, which is on the upper end of the NDC range for the power sector (as claimed by the Draft IRP 2023), and above the suggested range according to the UCT: ESRG (Marquard et al., 2021), the World Bank's South African Country Climate and Development Report (World Bank, 2022), and the JET-IP (The Presidency, 2022).

Compared to Scenario A, the total system investment requirements are 2% and 16% higher for scenarios B and C, respectively, due primarily to the less optimistic technology learning rates and higher fuel prices in scenarios B and C, However, scenarios B and C require less generation and grid Capex than Scenario A.

In terms of grid expansion, the key corridors that the model builds under all scenarios are the western, central, and eastern 765 kV corridors. This is in line with Eskom's TDP (Eskom-NTCSA, 2024b) and the Strategic Transmission Corridors. The other significant corridors are also generally in line with the TDP and the Strategic Transmission Corridors. The main difference identified between the model results and the TDP and Strategic Transmission Corridors is the Northern Cape to Free State corridor, which predicts a higher capacity than that reflected in the TDP and Strategic Transmission Corridors. This may be due to the TDP and Strategic Transmission Corridors focusing on a medium-term time horizon (up to 2034), as opposed to this study, which focuses on a longer-term time horizon (up to 2050).

4.8 Recommendations

Scenario A is consistent with a local and global green transition, offers the best option for exports in the context of regulations such as CBAM, meets the NDC targets, and does so with the lowest total investment[25]. Subject to assessment of the socio-economic impact of Scenario A, which will be included in a supplementary report, pursuing the technology transition, energy mix, and associated investment requirements of Scenario A, as summarised in Table 28, is recommended. Since achieving Scenario A is contingent on the realization of the relevant local and global pathway assumptions, it is recommended that the Government pursue policy decisions that enable this pathway and its associated assumptions.

Table 28: Quantified Recommendations for Scenario A

Metric	Units	2030	2040	2050

[25] *Total system investment = Total generation Capex + Total generation Opex (including fuel) + Total transmission (including distribution collector networks) Capex, discounted 8% to 2024 real terms*

Operational solar PV capacity	GW	31	67	99
Operational wind capacity	GW	18	40	48
Operational BESS capacity	GW	11	31	53
Operational gas capacity	GW	9	20	23
Operational coal capacity	GW	14	14	10
Operational CCS capacity[26]	GW	0	10	10
Operational hydro capacity	GW	4	5	5
Operational nuclear capacity	GW	2	2	2
CO_2 emissions from electricity	Mt p.a.	122	15	8
Annual average Capex investment[27]	R bn p.a.	227	176	176

Scenario B is premised on a local and global environment that is less focused on a green transition, and as a result, its key drivers differ from Scenario A, e.g., technology learning rates (for VRE and BESS) are less optimistic, fuel prices are higher, and the cost of capital for new fossil fuel generation is closer to that of renewable energy. In this environment, Scenario B represents the energy mix with the lowest investment requirement and partially exceeds South Africa's NDC target. While the annual average Capex investment is lower than Scenario A, the total system investment is higher. Should the local and global pathway assumptions shift towards Scenario B, a policy space may well be created that justifies selecting a technology transition, energy mix, and associated investment requirements aligned with Scenario B, as summarised in Table 29. The major difference between Table 28 and Table 29 is the coal capacity. Despite the economic rationale justifying Scenario B, South Africa may still want to align its policy choices with Scenario A in response to wider climate impacts resulting in Southern Africa warming at twice the global rate (Scholes and Engelbrecht, 2021).

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[26] *Operational CCS capacity is a subset of operational coal capacity*

[27] *Includes generation and transmission (including distribution collector networks) Capex, discounted 8% to 2024 real terms. Excludes generation Opex.*

Table 29: Quantified Recommendations for Scenario B

Metric	Units	2030	2040	2050
Operational solar PV capacity	GW	21	48	64
Operational wind capacity	GW	11	24	33
Operational BESS capacity	GW	2	26	33
Operational gas capacity	GW	7	18	26
Operational coal capacity	GW	34	10	10
Operational CCS capacity[28]	GW	0	10	10
Operational hydro capacity	GW	4	5	5
Operational nuclear capacity	GW	2	2	2
CO_2 emissions from electricity	Mt p.a.	181	37	51
Annual average Capex investment[29]	R’bn p.a.	110	158	158

Scenario C reflects an abandonment of South Africa’s NDC commitments due to a breakdown in global alignment and acute economic cost challenges, but retains a focus on electricity production through least cost and security of supply. With the local and global environment no longer focused on a green transition, the key drivers differ from scenarios A and B, e.g., technology learning rates (for VRE and BESS) are pessimistic, fuel prices are even higher, and the cost of capital for new fossil fuel generation is equal to that of renewable energy. While the annual average Capex investment remains lower than Scenario A, the total system investment required is the highest of all scenarios. If the local and global pathway assumptions shift towards Scenario C, a policy space may well be created that justifies selecting a technology transition, energy mix, and associated investment requirements aligned with Scenario C, as summarised in Table 30. Despite the economic rationale justifying Scenario C, South Africa may still want to align its policy choices with scenarios A or B in response to wider climate impacts, resulting in Southern Africa warming at twice the global rate (Scholes and Engelbrecht, 2021).

[28] *Operational CCS capacity is a subset of operational coal capacity*

[29] *Includes generation and transmission (including distribution collector networks) Capex, discounted 8% to 2024 real terms. Excludes generation Opex.*

Table 30: Quantified Recommendations for Scenario C

Metric	Units	2030	2040	2050
Operational solar PV capacity	GW	23	41	52
Operational wind capacity	GW	10	23	32
Operational BESS capacity	GW	2	16	25
Operational gas capacity	GW	5	19	29
Operational coal capacity	GW	34	15	11
Operational CCS capacity[30]	GW	0	0	0
Operational hydro capacity	GW	2	5	5
Operational nuclear capacity	GW	2	2	2
CO_2 emissions from electricity	Mt p.a.	181	127	129
Annual average Capex investment[31]	R'bn p.a.	142	191	191

The optimal combination of capacity, energy mix, and CO_2 emissions trajectory is difficult to identify definitively, as South Africa has limited control of the external, global pathway assumptions, and local pathway assumptions are somewhat linked to the global assumptions. The following broad recommendations apply across the range of pathways and related scenarios considered in this study:

- **Significant expansion of VRE technologies:** The findings from this study, supported by various mitigation modelling exercises for South Africa, including those by the NBI, Meridian Economics, the CSIR, and the UCT: ESRG, all recommend focusing on a significant expansion of VRE as part of the least-cost energy solution (NBI, 2022; Meridian Economics, 2024; CSIR, 2020; Marquard et al., 2021).

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[30] *Operational CCS capacity is a subset of operational coal capacity*
[31] *Includes generation and transmission (including distribution collector networks) Capex, discounted 8% to 2024 real terms. Excludes generation Opex.*

- **Incorporate gas and battery storage to support VRE technologies:** This study, supported by others previously listed (NBI, 2022; Meridian Economics, 2024; CSIR, 2020; Marquard et al., 2021), finds that the least-cost energy mix should incorporate gas-fired power plants and BESS to provide the necessary support and flexibility required from a large penetration of VRE capacity. BESS is effective for stabilization requirements measured in seconds and hours, while gas is more suitable for stabilization measured in hours to days (The Presidency, 2023; NREL, 2019). Note that gas should not be adopted as an alternative baseload power source to coal due to its higher costs, price volatility (due to being traded in USD), and its higher carbon footprint relative to VRE (IEA, 2024; UNEP, 2023).
- **No new coal and nuclear plants:** Results from the least-cost modelling in this study, supported by the findings from other similar studies (NBI,2022; Meridian Economics, 2024; CSIR, 2020; Marquard et al., 2021), as well as the Reference Case from the Draft IRP 2023 and Draft IRP 2024, indicate that new coal and nuclear capacity should not form part of the least-cost energy mix under a wide range of scenarios and sensitivities. This conclusion is based on the current mainstream projections of the costs of conventional nuclear and small modular reactors (SMRs). However, if learning rates turn out to be similar to what advocates of nuclear power propose, these cost projections relative to the costs of VRE may change. In addition to reduced costs of nuclear power, the costs of VRE may start to rise in the 2030s if the whole world commits to an accelerated energy transition due to natural resource constraints affecting the supply of construction materials (WEF, 2024b). Either way, in the unlikely event that nuclear does become affordable in the near future, the earliest it could come online is in the mid-2030s. For a developing country like South Africa, nuclear only becomes affordable within the next decade, thus pushing commissioning of nuclear into the 2040s.
- **AQ retrofits only for plants with longer remaining life:** Both scenarios A and B had a strict mandate for AQ compliance in 2030 and 2035, respectively, and opted to decommission the coal plants that had shorter remaining lifetimes, leaving only Medupi, Kusile, Majuba, and Kendal (Scenario A only) in operation. From a least-cost perspective, this suggests that it is more economical to decommission plants with shorter remaining lifetimes than to deploy AQ retrofits and keep them operational. A thorough cost-benefit analysis, based on plant-specific cost estimates, should be conducted before investing in AQ retrofits for plants with shorter remaining lifetimes.
- **Investigate and monitor the feasibility of CCS technology:** CCS is deployed in scenarios A and B for plants with longer remaining lifetimes, i.e., Medupi, Kusile, Majuba, and Kendal (Scenario A only). While CCS technology deployment is increasing internationally, its current scale and maturity are far from what would be required to successfully implement it on these

power plants. The future feasibility and cost-effectiveness of utility scale CCS will depend on its global rate of adoption. If available and commercially viable at scale, CCS will be deployed for scenarios A and B in 2035 and 2040, respectively, allowing some time for this technology to mature and reach the cost projections and required scale for adoption on South Africa's coal fleet.

- **Maintain existing infrastructure:** Achieving energy security and reliability depends as heavily on maintaining existing energy infrastructure as it does on building the right infrastructure. To limit and ultimately eliminate load shedding, the existing coal fleet must meet its availability targets, and transmission and distribution infrastructure must transport electricity to consumers reliably and efficiently.
- **Co-locate renewable energy generation infrastructure with demand:** Co-locating renewable energy generation infrastructure with demand centres, such as industrial parks, data centres, or urban areas, can significantly reduce transmission losses and improve energy efficiency. Co-location can facilitate the integration of renewable energy sources with local energy needs, thus enhancing grid stability and reliability (Constellation Energy, 2025). This kind of responsive demand-driven locational planning of quick-to-build VRE (plus backup) to meet changing demand profiles supplants the now-outdated baseload approach, which centred on procuring supply driven, slow-to-build, large-scale, coal-fired power plants.
- **Implement decentralised energy systems:** While this study focused on the national grid, decentralised energy systems can provide power to communities and newly established informal settlements that are not connected to the national grid (Roff et al., 2023). Renewable energy-based microgrid systems are particularly viable for rural communities, improving quality of life and creating job opportunities (Roff et al., 2023).
- **Monitor disruptive technologies:** Monitor the development of disruptive technologies in the electricity sector. Globally, there is a large focus on research, development, and scaling up of new technologies in the electricity sector. Some of the potential disruptive technologies in the electricity sector are discussed further in Appendix E and include SMR, offshore wind, long-term energy storage, and grid digitalization.
- **Consider policy and regulatory changes that support green industrialization and the reduction of GHG emissions:** As observed from Scenario A and detailed in Section 3.3, with a favourable set of local and global conditions, a transition to a secure, reliable, modern, and affordable electricity system that meets South Africa's NDC targets can be achieved. Key policy aspects to consider, informed by the policy assumptions that impacted the energy modelling, include sufficient carbon tax levels, a mandatory requirement for AQ compliance, and enabling low costs for VRE, BESS, and gas technology, as well as low fuel costs. Further discussion on policy and regulatory aspects is provided in Section 7.

5 Market Sounding of the Energy Infrastructure Funding Gap

5.1 Introduction

One of the key research questions of this study is regarding the potential energy infrastructure funding gap in South Africa. The funding gap in the context of the market sounding refers to the comparison of available capital and required capital as defined below:

1. **Required capital:** The projected required levels of Capex (excluding operating costs, capitalized interest, and funding costs) to support the required energy infrastructure rollout until 2050.
2. **Available capital:** The anticipated levels of available funding from debt, equity, and blended finance providers (as indicated by the market sounding participants), for energy, transmission, and distribution infrastructure projects in South Africa.

A soft or informal market sounding [32] exercise was conducted with a select group of active capital providers in the South African energy sector. In support of the market sounding, OEG was responsible for the energy modelling and estimated that the total required capital was R2.2 trillion (in 2024 real terms) over the forecast period until 2050, excluding operating costs, capitalized interest, and funding costs (see Figure 46 below). At the time of the market sounding interviews, the technical modelling was still ongoing, and the estimated R100 billion per annum (in 2024 real terms) from 2024 to 2050 was derived from the Draft IRP 2023 and additional reputable public sources of information. This was to frame OEG's initial estimates and assumptions for the required capital, including the Capex quantum, technology mix, and phasing.

The assumptions applied to frame the required capital at R100 billion per annum are based on the expected electricity generation, transmission, and distribution infrastructure requirements for South Africa over the forecast period until 2050. This estimate should be considered as notional, and was used as a starting point for engaging with participants during the market sounding. Further details are provided in Section 5.2 (Methodology) and Section 5.3 (Assumptions and Limitations).

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[32] *Market sounding is an approach to gauge investors' market interest in funding projects. Due to the lack of project-specific information and the timeline spanning 25 years, the questions in this instance are less detailed and are referred to as a soft market sounding exercise. In addition, relative to traditional research market soundings, where participants may submit responses in writing and detailed information is shared beforehand, participants were not required to submit answers before the meeting.*

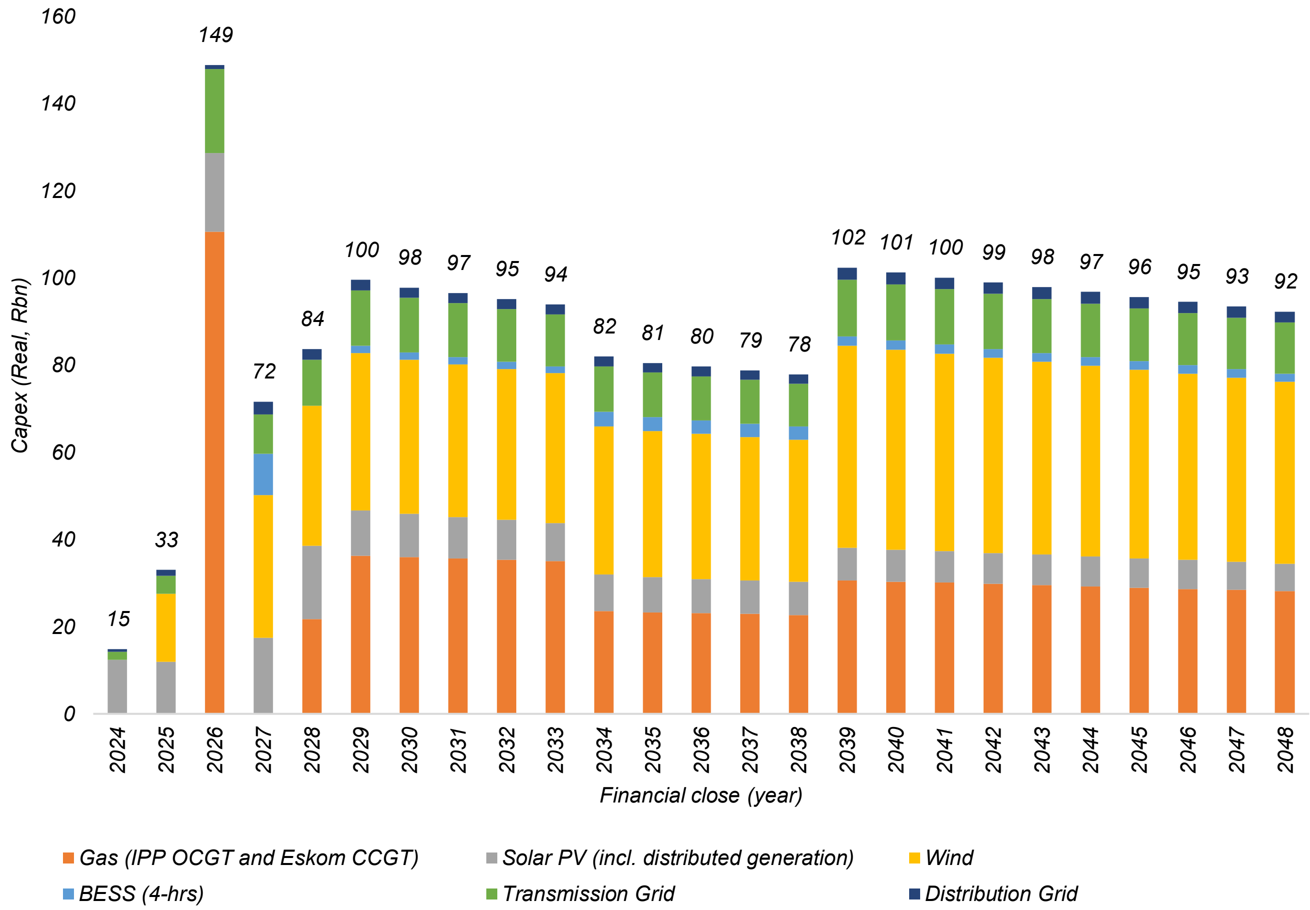

Figure 46: Estimated Forecast Capital Expenditure (Capex) for Energy Infrastructure in South Africa Used for the Market Sounding (R'bn, 2024 real terms)[33]

Sources: DMRE (2023a) and OEG assumptions.

[33] *The graph represents the annual financial close and assumes 2 years of construction time to allow operations to begin in 2050, therefore covering a period from 2024 to 2048.*

5.2 Methodology

To understand how to quantify and address the potential funding gap, a market sounding exercise was conducted with a select group of active participants in the South African energy market who are prospective providers of capital. These market sounding participants were selected to represent a balanced market perspective and comprise the following categories listed in Table 31.

Table 31: Prospective Funders and Market Sounding Participants

Equity	Debt	IPP	Blended Finance	Bank
• Local infrastructure • Private equity funds	• Institutional debt funds • Local Developmental Finance Institutes • Multilateral Lending Agencies	• Local and international IPPs (multi-technology focused funds)	• Government • Treasury • Infrastructure Fund	• Local commercial banks

The market sounding was conducted via an informal interview with participants. An interview guide and briefing document were shared with participants ahead of the interview. The document provided an overview of the team’s existing mandate, including the rationale behind the market sounding and the underlying assumptions. A questionnaire was also shared that examined the prospective levels of available capital and the current challenges or key enabling factors that would direct additional funding towards the energy sector.

5.2.1 Market Sounding Interview Guide

With reference to the agreed-upon scope, the market sounding interview guide was developed to assist with answering the key research questions related to the funding gap. The market sounding interview guide comprised the following questions:

1. In the context of unpacking the total quantum of funding available to solve for the funding gap, please provide us with a high-level indication of the total funds (either debt or equity) available for allocation towards energy infrastructure investments within the South African market over the forecast period?
2. What are the current limitations or obstacles you may have in relation to raising or allocating additional funds towards energy infrastructure in South Africa?

3. In your opinion, what do you believe to be the key enablers or catalysts that would encourage additional capital formation and allocation of funds within the South African energy infrastructure sector? Some of the key themes which could play a role include:
    a. Policies / regimes (i.e., asset allocation constraints, tax incentives etc.); and
    b. The role of blended finance (i.e., public, and private sector collaboration).
4. Do you believe there are any innovative funding approaches which have not been considered in the South African market, which could further incentivize significant capital formation and allocation within the energy infrastructure sector?
5. What level of market risk are you prepared to take with specific reference to off-take mechanisms and the current energy market structure?

5.2.2 Output Matrix Development

An output matrix has been designed to capture both quantitative and qualitative responses from prospective funders as part of the soft market sounding exercise. Specifically, this entails:

- An indicative quantum of funding (debt and equity) available for allocation towards energy infrastructure investments in the South African market.
- Key limitations and obstacles in relation to raising or allocating funds towards energy infrastructure in South Africa.
- Possible enablers and catalysts that would encourage additional capital formation and fund allocation in the South African energy infrastructure market.
- The appetite of market sounding participants for taking on market risk.

These outputs were developed by scoring the responses from the market sounding participants on a scale between zero and five. As such, for each key theme identified, the responses from the market sounding participants were evaluated comprehensively and captured on the scale. While the scoring system provided a quantitative measure of the responses, qualitative aspects such as the depth and clarity of the responses were also considered.

5.2.3 Report Development

Based on the output matrix, a report was developed to address the key research questions related to the funding gap. This report will be used as an input for estimating the finance options for the funding gap, as well as to support Section 7 (Policy and Regulatory Review).

5.3 Assumptions and Limitations

As mentioned in the introduction, the technical modelling workstream was still being finalized when the market sounding interviews were conducted. Therefore, OEG utilized the Draft IRP 2023 and their own assumptions as a basis for annual Capex per technology, technology learning rates, and the phasing of implementation thereof. As such, the required capital assumption of R100 billion per annum was indicative, and the market sounding process did not look to test or verify the information provided by OEG.

The following assumptions have been applied to the market sounding:

- A 70% debt and 30% equity funding split has been applied based on a conservative market-related estimate.
- To determine the level of the funding gap, an assumption of R100 billion (in 2024 real terms) of total funding required per annum until 2050 was made. This excludes operating costs, capitalized interest, and funding costs. This was based on OEG's initial estimated total required capital of R2.2 trillion (in 2024 real terms) over the forecast period until 2050[34], which excluded operating costs, capitalized interest, and funding costs.
- The rationale for utilizing the R100 billion (in 2024 real terms) per annum and excluding operating costs, capitalized interest, and funding costs is based on the following key factors:
  - To determine the operating costs, capitalized interest, and funding cost components that typically comprise part of the project size and costs, a detailed financial modelling exercise is required on a project-by-project basis. Without this project and funding information, this task would not add additional value to the overall objective of the market sounding.
  - The information provided by the Draft IRP 2023 and the assumptions by OEG were sufficient to contextualize the Capex requirements without requiring significant assumptions on forecast funding rates and the Consumer Price Index (CPI).
  - A round number contributed to the ease of discussion with market sounding participants by ensuring that the focus remains on the questions aimed at understanding the funding gap (listed in Section 5.2.1 above) rather than going into unnecessary discussions on the underlying assumptions of the capex.

The following limitations apply to the market sounding:

- Due to the inherent confidentiality and commercial sensitivity of innovative funding approaches, a potential limitation is that the market sounding participants may not have shared all the approaches currently being considered in the South African energy infrastructure market. This is due to the potential risk posed to the commercial objectives of the market sounding participants. Furthermore, the participants may be cautious about unwittingly disclosing inside information.

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[34] R2.2 trillion divided by 26 years (2024 up to 2050) is approximately R81.5 billion per annum. Therefore, a quantum of R100 billion allows headroom of approximately 18%.

- Given the varying commercial objectives of different types of market sounding participants, there is an inherent limitation to the comparability of the outputs and key themes identified, e.g., debt funders have more conservative risk exposure perspectives than equity funders. As a result, the participants have not consistently identified the same outputs and key themes throughout the market sounding exercise. As such, not every market sounding participant has been included in each output and key theme discussed in the following section.

5.4 Findings

5.4.1 Quantum of Funding Available to Solve for the Funding Gap

As indicated in Figure 47 below, most of the market sounding participants (other than one international participant) indicated that there is no funding gap for energy infrastructure within the South African market over the short-to-medium term. However, local market sounding participants have indicated that there will be a significant funding gap in the longer term (see Section 5.5.1). In addition, local commercial banks are confident that round seven of the REIPPP Programme will be fully funded.

Scale (0 - large funding gap; 5 - no funding gap)

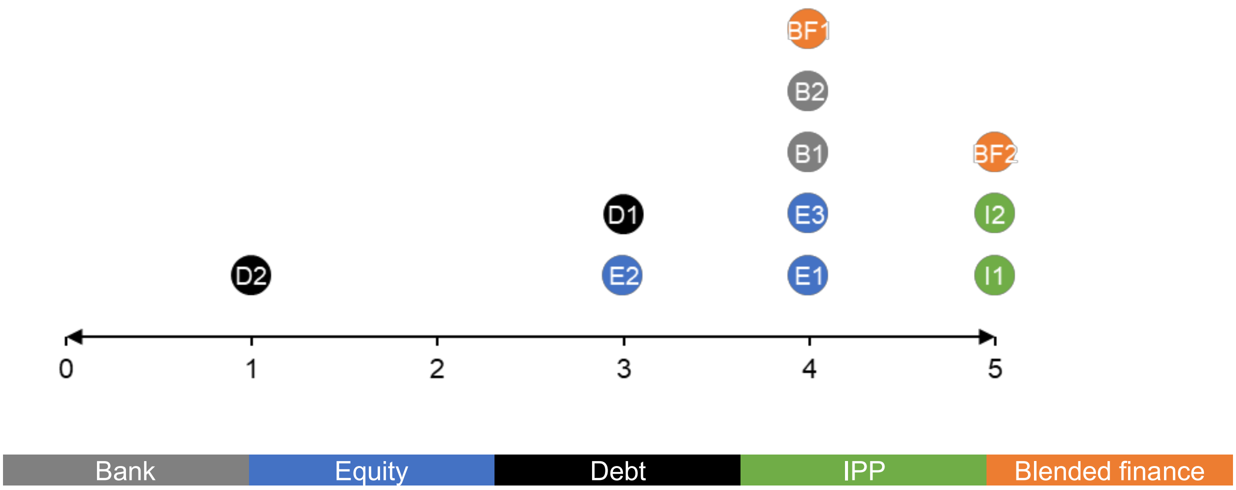

Figure 47: Funding Quantum Available Over the Short-to-Medium Term

5.4.2 Pricing as a Limitation to the Financing of Renewable Energy Infrastructure

As shown in Figure 48, the market sounding participants indicated that pricing is a significant barrier and limitation to the financing of renewable energy infrastructure in South Africa. Market sounding participants attribute this to the highly competitive nature of the current energy infrastructure market, particularly for generation infrastructure, where pricing levels on debt funding instruments and the returns for equity providers are decreasing as they no longer adequately compensate funders and investors for the associated risks taken on these generation projects. From a transmission infrastructure perspective, the same logic does not apply, given that the market is still not well developed in South Africa.

Scale (0 - no funding gap; 5 - large funding gap)

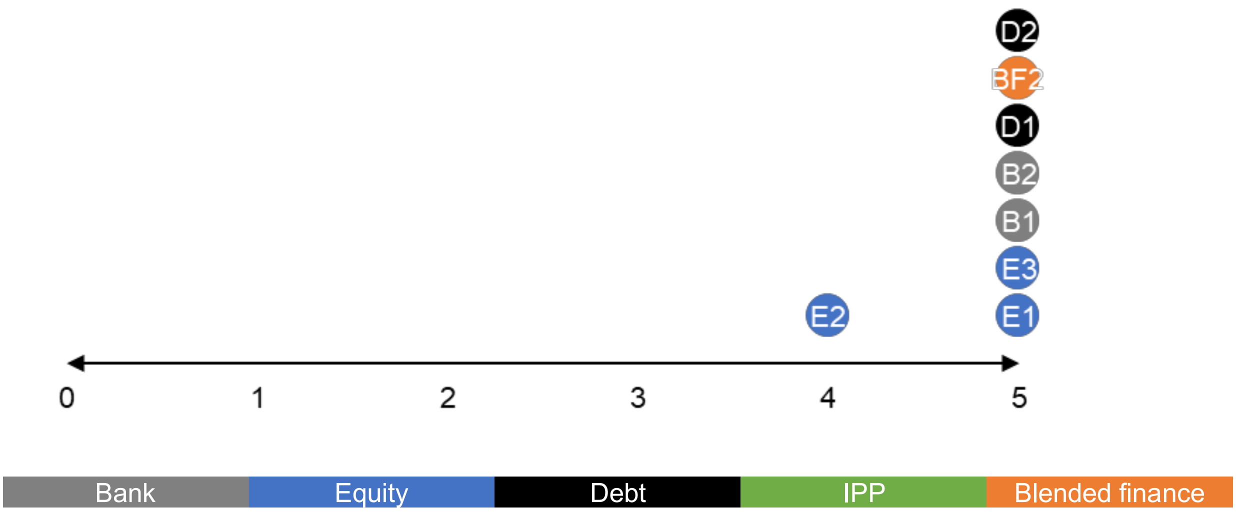

Figure 48: Pricing as a Limitation to Financing Renewable Energy Infrastructure

5.4.3 Policy Uncertainty as a Limitation to Financing for Renewable Energy Infrastructure

As indicated in Figure 49, policy uncertainty within the South African energy infrastructure market is a significant limitation for participants when allocating additional funds to energy infrastructure investments. From the market sounding, it was clear that the primary concern related to uncertainty and the unpredictability of policies and frameworks related to transmission and distribution infrastructure, which introduces additional complexities into the investment process. Further detail is provided in Section 5.5.3.

Scale (0 - policy uncertainty is not a limitation; 5 - policy uncertainty is a limitation)

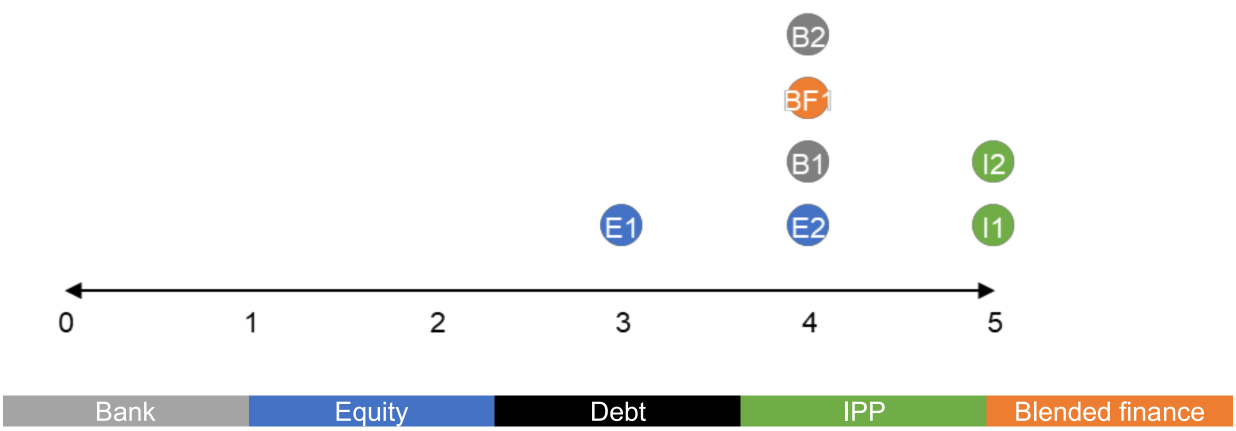

Figure 49: Policy Uncertainty as a Limitation

5.4.4 Blended Finance to Facilitate Financing for Energy Infrastructure

Blended finance refers to the strategic use of development finance to mobilize private capital flows to emerging markets. Blended finance has been identified by market sounding participants as a potential mechanism to attract debt funding for investments in energy transmission infrastructure. From a generation infrastructure perspective; however, the participants indicated a limited scope for investment given that the market is already well-established (see Figure 50 below).

Scale (0 - blended finance is not an enabler; 5 - blended finance is an enabler)

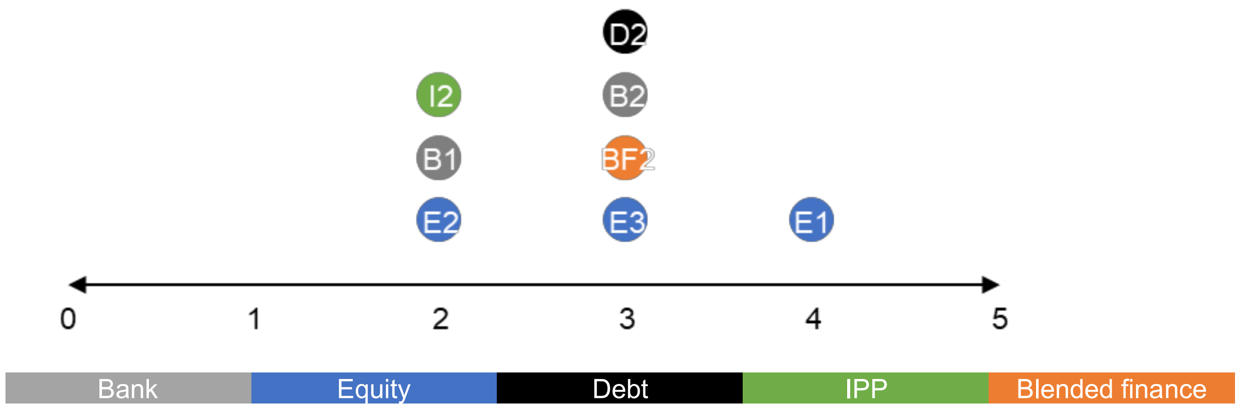

Figure 50: Role of Blended Finance as an Enabler for Financing Energy Infrastructure

5.4.4.1 Credit enhancements for financing renewable energy infrastructure

As illustrated in Figure 51, the market sounding participants believe that credit enhancements play a significant role in attracting debt funding for the investment in energy infrastructure within the South African market. While the commercial banks have indicated that credit enhancements play a moderate role in attracting debt funding, pension funds and IPPs have indicated that credit enhancements are also important for attracting debt funding for investment in South African energy infrastructure. Further details are provided Section 5.5.5.

Scale (0 - credit enhancements are not an enabler; 5 - credit enhancements is an enabler)

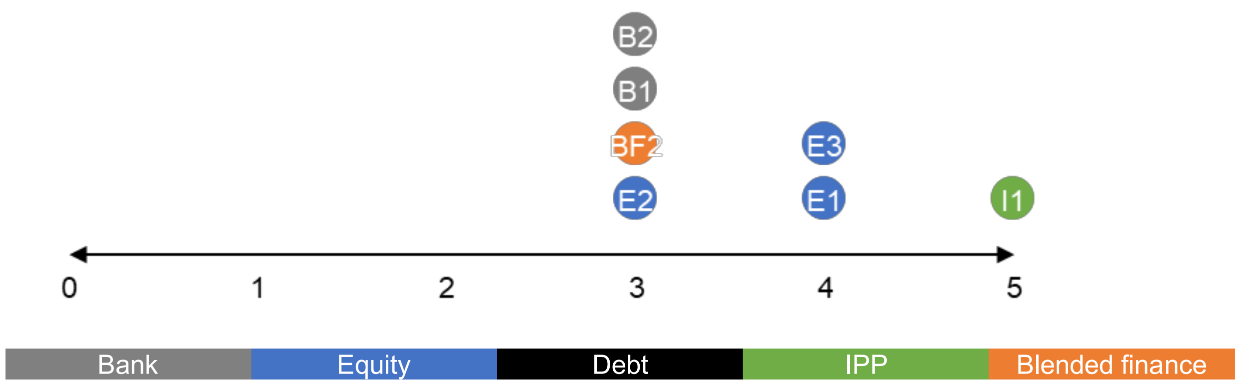

Figure 51: Role of Credit Enhancements as an Enabler for Funding Renewable Energy Infrastructure

5.4.4.2 Market risk level in the current renewable energy infrastructure environment

As indicated in Figure 52, the market sounding participants predominantly indicated that they have little appetite to take on this market risk, as the wholesale market is currently not mature enough in South Africa. However, participants have indicated that there will be an increase in energy aggregation players in the near to medium term in South Africa due to off-takers' lack of balance sheet strength, and thereby, their inability to provide sufficient long-term commitments to secure a long-term PPA.

The market sounding indicated that equity investors have a larger appetite to take on market risk due to their view on future energy prices and their increased appetite for risk compared to debt funders. One equity investor indicated a stronger appetite to take on market risk in the current environment due to their views on the energy demands and projected tariffs and, therefore, they do not require long-term take-or-pay arrangements to get comfortable to provide long debt tenors to drive tariff efficiency.

Scale (0 - no appetite for market risk; 5 - large appetite for market risk)

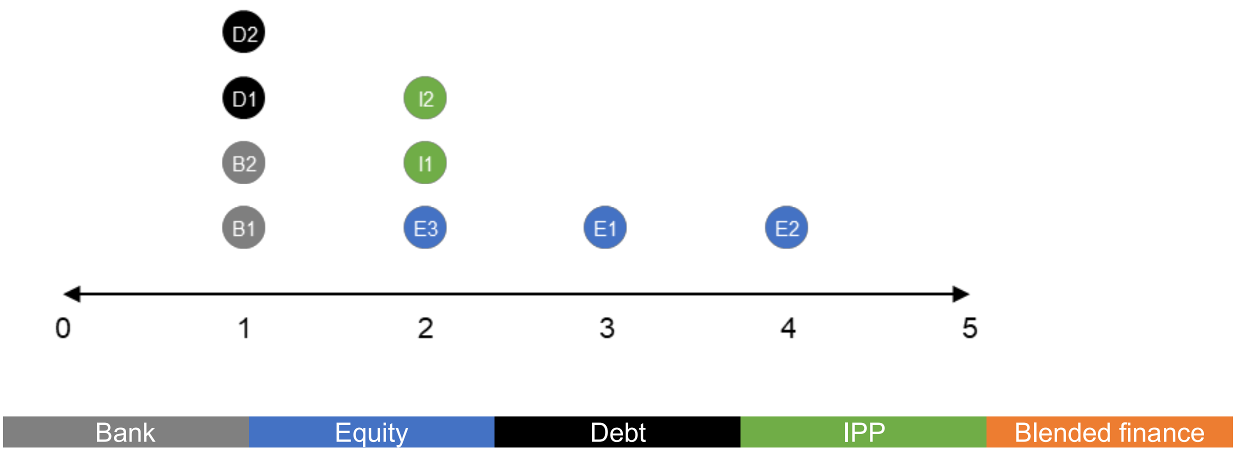

Figure 52: Level of Appetite for Market Risk Which Market Sounding Participants are Willing to Take in the South African Renewable Energy Infrastructure Environment

5.4.5 Additional Themes Identified During the Market Sounding by Participants

Based on the feedback from the market sounding participants, responses have been separated into three sub-categories listed below including a) obstacles or limitations when allocating additional funds towards energy infrastructure, b) key enablers and catalysts which would encourage additional capital formation and allocation of funds to energy infrastructure, and c) factors which influence the level of market risk which funders are willing to take within the energy infrastructure market. Detailed explanations of these additional themes are provided in Section 5.5.7.

5.4.5.1 *Obstacles or limitations when allocating additional funds towards South African energy infrastructure*

- Programme inconsistency and the resultant lack of a bankable project pipeline,
- Eskom's inability to process the substantial number of applications for the Eskom Budget Quote (BQ) process,
- Income Tax Act 58 of 1962 (as amended) Section 23M limitation on the deductibility of interest on debt,
- Lack of clarity for energy transmission infrastructure policy, commercial structure, and framework,
- Lack of ability to execute the construction of renewable energy projects,
- Internal and external pressures from stakeholders to fund gas-to-power projects,
- Uncertainty created by the Government's IRP, and
- Lack of coordination between public stakeholders.

5.4.5.2 Key enablers and catalysts to encourage additional capital formation and allocation to the South African energy infrastructure sector:

- Education for a private market sector and trustees of pension funds to encourage additional capital flows,
- Increased alternative asset allocations by South African pension funds,
- National Treasury's guarantees provided to off-takers with lower credit quality,
- Pilot projects within the transmission infrastructure sector to support large-scale future rollout,
- Development of a robust licensing and tariff regime,
- Supporting policies and framework surrounding private funding, and
- Innovative funding approaches:
    - Real Estate Investment Trust (REIT) vehicles for funding energy infrastructure to enable public investment and attract direct foreign investment,
    - Provision of guarantees for EPC contractors,
    - Facilitation of swaps on ZAR-based lending,
    - Longer-term funding, such as 30-year loan tenors for energy transmission infrastructure projects, and
    - Alternative funding and operating models can unlock funding for transmission infrastructure.

5.4.5.3 *Factors influencing the level of market risk that funders are willing to take within the energy infrastructure in the South African market*

- Development of a wholesale access energy market to encourage additional market participation.

5.5 Discussion

5.5.1 Quantum of Funding Available to Solve for the Funding Gap

The market sounding participants indicated that over the short to medium term, there will be no funding gap for energy infrastructure in South Africa. However, without market and policy reform, there will be a long-term funding gap. This is supported by several factors included in the limitations or obstacles listed in Section 5.5.7.

In addition, the following responses from the participants should be noted regarding the total funding quantum available to solve the funding gap:

- **Secondary market role**: The secondary market's ability and appetite to invest in commercial banks' debt syndication processes are key considerations when determining the funding gap. Without investor appetite for debt syndication, commercial banks become hesitant to continue funding additional energy infrastructure investments due to exposure limitations.
- **REIPPP round seven:** Regarding the long-term funding gap, local commercial banks believe that round seven of the REIPPP will result in energy generation infrastructure being fully funded.

5.5.2 Pricing as a Limitation to Financing Renewable Energy Infrastructure

According to the market sounding participants, the pricing on debt funding instruments remains a significant barrier when determining the funding available for investment, as it deters funders from allocating debt to energy infrastructure investment in the South African market. This is primarily driven by the highly competitive nature of the current energy infrastructure market, as pricing levels and returns are becoming less attractive and no longer compensate investors adequately for the risks associated with renewable energy projects.

To address this, pricing across the debt and equity funding instruments must be rebalanced to attract investors and ultimately stimulate the required funding for energy generation, distribution, and transmission infrastructure.

Currently, net interest margin returns are below 200 basis points, which the participants deemed low, and this level of pricing fails to account for the inherent risks associated with energy infrastructure investments. Low returns on debt funding instruments will result in the commercial banks' debt syndication programmes becoming less attractive to the secondary market, thereby resulting in less capital being allocated to fund energy infrastructure.

The secondary market, specifically pension funds, has access to a significant quantum of funding and will continue to balance risk and liquidity with returns on their investment portfolios in pursuit of optimal portfolio management. As such, a cautious investor would prefer to invest in a listed South African 20-year Government Bond, which had a yield of 12.50% during June 2024, compared to syndicated debt products for financing energy infrastructure, which offer a yield of 10.35%. These percentages reflect the three-month JIBAR + 200 basis points. Debt syndication participants are not appropriately compensated for the level of risk and liquidity that is taken on, as the debt syndication instrument is not listed on an exchange and therefore does not appropriately compensate investors for the lack of liquidity. The credit quality of the borrower is also weaker than that of the South African Government.

Addressing the challenges associated with pricing on debt funding instruments is crucial to bridging the long-term funding gap in South Africa's energy infrastructure. This can be achieved by rebalancing pricing to compensate for the associated risk.

5.5.3 Policy Uncertainty as a Limitation to Fund Allocation for Renewable Energy Infrastructure

Policy and framework uncertainty has been identified as a significant limitation to funders allocating additional funds to energy infrastructure investments within the South African market. The primary concern related to policy uncertainty for energy transmission and energy distribution infrastructure is the unpredictability that it introduces into the investment process. As policies provide a framework for energy infrastructure developers to operate in, any uncertainty in this environment creates challenges for potential debt funders. This uncertainty can lead to potential debt funders being hesitant to invest in energy transmission and distribution infrastructure, thereby exacerbating the funding gap.

Policy uncertainty includes regulatory changes, shifts in energy priorities, changes in tariff structures, and inconsistencies in the implementation of public procurement programmes. These uncertainty factors impact the perceived level of risk associated with energy infrastructure projects, making them less attractive to potential debt funders.

5.5.4 Blended Finance to Facilitate Financing for Energy Infrastructure

The role of blended finance was identified as a potential mechanism to attract debt funding for investment in energy transmission infrastructure. In contrast, there is a limited role for blended finance for investment in energy generation infrastructure, which already has a well-established market.

The nature of energy transmission infrastructure investment requires substantial debt capital and long-term investment horizons, given the associated significant risks, including construction risk, operational risk, and regulatory risk. Blended finance can play a crucial role in mitigating risks for debt funders investing in energy transmission infrastructure, thereby making investment more attractive to potential debt funders such as commercial banks and pension funds, and increasing the allocation of debt funding to energy infrastructure within the South African market. Blended finance can be strategically positioned to reassure developers and commercial lenders and play a key role in funding infrastructure investments in gas-to-power projects, particularly in the midstream market, such as pipeline transportation, storage, and processing.

5.5.5 Credit Enhancements for Financing Renewable Energy Infrastructure

The market sounding participants have indicated that credit enhancements do play a significant role in attracting debt funding for investment in energy infrastructure within the South African market.

Local commercial banks indicated that credit enhancements play a moderate role in attracting debt funding, while pension funds and IPPs have indicated that credit enhancements play an important role in attracting funding.

The IPP indicated that credit enhancements can play a significant role, particularly for EPC contractors in the form of performance guarantees. In addition, the participant indicated that first-loss backstops can ensure that energy developers can withstand unforeseen market instability and volatility during the construction period of renewable energy projects.

Credit enhancements have a larger role to play in energy transmission infrastructure, as there is more experimentation and policy uncertainty compared to energy generation infrastructure. In addition, the market sounding participants believe that credit enhancements could play a key role in mobilizing private debt capital investment in energy transmission infrastructure.

In addition, credit enhancements can play a crucial role in the gas-to-power midstream market to mobilize capital allocation from the private sector. First-loss backstops can be used as a form of credit enhancement, whereby a DFI absorbs the first tranche of any losses at a pre-determined level.

5.5.6 Level of Market Risk in the Current Renewable Energy Infrastructure Environment

Most market sounding participants indicated that they have little appetite to take on this market risk in the current energy infrastructure market in South Africa, as the wholesale market is still not mature enough.

More recently, however, there has been an increased entry of energy aggregators, who combine energy from energy generators and distribute to the end-user through Eskom's network. The energy aggregation model typically entails shorter-term PPAs when compared to traditional 20-year PPAs, with larger scale aggregators offering terms as short as one year. As a result, a debt funder would be required to take on market risk when funding developers that enter short-term PPAs with an energy aggregator. This is due to the absence of an off-take agreement for the tenor of the useful lifespan of the energy generation assets.

Furthermore, shorter-term PPAs for wind technology may become more attractive when compared to solar PV technology, as the latter will be difficult to resell at an attractive level for investors due to the rapid technological advancement and increased adoption of rooftop solar PV systems, which ultimately drives down the cost of producing energy from these technologies.

Commercial banks have indicated that there will be additional debt funding allocated to energy aggregators as the market matures. The market will be deemed mature once the day-ahead and week-ahead energy markets in South Africa obtain additional liquidity, which will require increased market participation and regulatory reform.

The day-ahead market enables energy generators, such as Eskom and IPPs, to inform the market operator on the quantum of electricity which they expect to generate the following day, and the tariff at which they are willing to sell this electricity. In contrast, energy consumers, such as municipalities or large industrial consumers, will inform the market operator of the quantity of electricity they require for the following day and the level of tariff they are willing to pay for that electricity. The market operator then matches the offers from buyers and sellers to determine the level of tariff for electricity for the next day.

Currently, the week-ahead market is not formalized in South Africa; however, market players obtain insights from forecasts, such as weather, energy availability, and other factors that could impact the level of electricity tariffs.

5.5.7 Additional Themes Identified During the Market Sounding by Participants

1) ***Limitations or obstacles in relation to raising or allocating additional funds towards energy infrastructure include:***

- **Programme inconsistency and the resultant lack of bankable projects:** Developers and commercial lenders are losing confidence in the public procurement programme, REIPPP, due to the programme's frequent postponements. Developers invest significant portions of their limited resources to prepare submissions to the public procurement programmes. This loss of confidence will result in less appetite to fund energy infrastructure projects within the South African market, as prospective debt funders require a consistent pipeline of bankable projects to efficiently deploy and allocate debt capital to energy infrastructure investments.
- **Eskom's inability to process the substantial number of BQ applications:** Due to the significant growth in renewable energy projects competing for grid capacity and connectivity, Eskom has become inundated with BQ applications, resulting in numerous projects being unable to reach bankability status. As such, available debt funding, which could have been deployed to energy infrastructure within South Africa, has been halted for these projects until Eskom approves the BQ applications.

- **Income Tax Act 58 of 1962 (as amended) Section 23M limitation on the deductibility of interest on debt:** Due to the interconnectedness of finance arrangements which pension funds enter into, Section 23M of the Income Tax Act limits the deductibility of interest expense on such financing arrangements and thus, deters pension funds from investing in certain debt funding instruments which fund energy infrastructure due to the unattractiveness of the interest deduction limitation.
- **Lack of clarity in the energy transmission infrastructure policy and framework:** Energy generation investment has recently been a key focus within the South African market, and as a result, the development of transmission policies and procurement has lagged, creating a bottleneck for the rollout of further utility scale renewable energy. Therefore, there have been less opportunities to fund energy transmission infrastructure. The lack of clarity in policy and framework has most likely increased the funding gap on energy generation investments due to the inability to connect such projects to grid infrastructure.
- **Inability to execute construction of renewable energy projects:** There is a shortage of key resources, such as advisors and technicians, which has resulted in fewer projects reaching financial close and commercial operational date, thereby reducing the quantum of debt funding allocated to energy infrastructure. For example, due to the recent lack of focus on transmission infrastructure, many transmission-focused EPCs have either closed or shifted their focus. The latter may cause an initial skills deficit, which is expected to be corrected over time.
- **Internal and external pressures from stakeholders to fund gas-to-power projects:** Funders are facing pressures from internal and external stakeholders not to fund gas-to-power projects due to their contribution to GHG emissions. Gas as an energy source is crucial for balancing the grid due to the increasing supply from wind and solar PV energy, which is inherently intermittent.
- **Uncertainty created by the Government's IRP:** The IRP is a strategic framework for planning the country's energy supply to meet future electricity demand while considering financial and environmental factors, amongst others. The IRP creates uncertainty for funders and IPPs by frequently revising its energy generation targets and timelines, which creates an unpredictable investment environment. This uncertainty is compounded by the plan's efforts to balance different energy sources, making it challenging for investors to gauge the long-term viability and profitability of their energy infrastructure opportunities and investments.
- **Lack of coordination among public stakeholders:** Market participants believe that there is room for improved efficiency and coordination among public stakeholders, which has resulted in delays and increased costs to project sponsors. The introduction of the NTCSA, with its stated objective and focus on transmission infrastructure, is a promising start; however, developing capabilities and building trust as a reliable SOE will require time.

2) ***Key enablers or catalysts that would encourage additional capital formation and allocation of funds within the South African energy infrastructure sector include:***

- **Education for the private market sector and trustees of pension funds to encourage capital flows:** There is a lack of understanding and awareness of energy infrastructure investments (and their respective risk and return profiles) in South Africa, specifically within the private market sector and among pension fund trustees. This discourages capital allocation. Adequate education of the private market sector and trustees of pension funds will encourage debt capital flows to energy infrastructure investments within the South African market. Educating the private sector market and pension fund trustees is a multifaceted approach that should involve educational workshops and seminars, collaboration with industry experts, or sharing case studies. Case studies articulate real-world examples, provide practical insights, and demonstrate the potential benefits of energy infrastructure investments.
- **Potential for increased asset allocations by South African pension funds:** The estimated South African pension fund market size is R4.6 trillion, with current allocations of alternative investments to energy infrastructure making up 2%. The international norm for asset allocation to alternatives and energy infrastructure is reportedly 5%. Therefore, on an illustrative basis of 5% to 10% of alternative energy assets, South Africa may gain access to between R230 billion and R460 billion in energy infrastructure funding.
- **Level of National Treasury's guarantees provided to off-takers with lower credit quality:** Commercial banks and pension funds have indicated that the National Treasury's guarantees play a fundamental role in increasing the credit quality of Eskom. The level of guarantee provided by the National Treasury is related to the appetite with which commercial banks and pension funds will finance energy infrastructure investments within the South African market. The extent of the guarantees provided to off-takers has reduced as part of the National Treasury's broader strategy to manage fiscal risk and ensure the sustainability of public finances.
- **Pilot projects within the transmission infrastructure sector:** As investment within energy transmission infrastructure in South Africa is still in its initial stages, market participants believe that there is an urgent need for pilot projects to test concepts relating to funding and operating assets within this sub-sector. These pilot projects will be crucial for the successful implementation of broader fundraising efforts, such as ITPs, similar to the REIPPP for energy generation.
- **Development of a robust licensing and tariff regime:** Particularly within energy transmission infrastructure, a robust and efficient tariff and licensing regime will be critical to building a pipeline of bankable projects. The market sounding participants have funding earmarked for this sub-sector, which can only be allocated once regulatory policies associated with transmission

infrastructure are well established. The participants also believe that NERSA will play a key role in developing the above-mentioned tariff regime for transmission infrastructure.

- **Innovative funding approaches** that have not yet been considered in the South African market, and could further incentivize significant capital formation within the energy infrastructure sector, include:
  - **Private funding:** Policy and frameworks for energy transmission infrastructure should cater to private funding, mirroring what was previously done successfully for generation infrastructure. This approach could unlock significant capital investment for energy transmission infrastructure.
  - **REIT vehicles for funding energy infrastructure to enable public investment and attract direct foreign investment:** An REIT vehicle for energy infrastructure can encourage additional fund allocation due to the tax and liquidity advantages of these listed vehicles.
  - **EPC contractor guarantees:** Guarantees provided to EPC contractors will promote confidence post financial close and thereby provide support to complete the construction of the energy infrastructure project.
  - **Swaps on ZAR-based lending:** Derivative instruments such as swaps on ZAR-based lending could encourage foreign capital allocators to allocate funding to South African energy infrastructure.
  - **Longer-term funding, such as a 30-year loan tenor for energy transmission infrastructure:** Due to the long-term nature of energy transmission infrastructure assets, longer-term funding could alleviate cash flow pressures on developers and borrowers.
  - **Alternative funding and operating models can unlock funding for transmission infrastructure:** Market participants believe that these alternative models could be an effective method for raising funding and operating assets with a broader national interest, such as transmission infrastructure. A particular reference was made to the operating and funding model used by Lebalelo Water Users Association for the Oliphants Management Model Programme (OMMP).

3) Factors which influence the level of market risk that funders are willing to take on include:

- **Development of wholesale access energy market:** The wholesale access energy market in South Africa is still in its infancy, and developing this market would encourage market participation from power producers, consumers, and financial institutions. It would create liquidity and pricing transparency for energy traders, enable energy aggregators to establish a track record, and foster confidence in the energy trading market. Such development would allow debt funders to allocate debt funding to energy aggregators with increased confidence, ultimately increasing the level of market risk that energy infrastructure funders are comfortable taking on.

5.6 Conclusion

To determine the level of the Capex funding gap and with reference to the assumptions and limitations in Section 5.3, a total funding requirement of R100 billion per annum until 2050 was assumed, consisting of R70 billion in debt and R30 billion in equity.

In the short term (i.e., projects related to round 7 of REIPPP and private projects in the corporate and industrial sector), most of the market sounding participants believe that there is no funding gap for energy infrastructure investments within the South African market.

However, in the long-term, the funding gap is significant for various reasons including unattractive pricing on senior debt, such as the margins below 200 basis points on JIBAR, the unreliability of the Government's energy procurement programmes, and the policy instability impacting the pipeline of bankable energy generation projects and delaying the procurement of transmission infrastructure, both of which negatively impact funders' appetite. In addition, local investors and banks may reach their limits of sector exposure allocations and debt holding levels if they are unable to syndicate their debt exposure effectively into the secondary market.

Market sounding participants believe that these enablers, catalysts, and innovative funding solutions could significantly address the funding gap by encouraging capital formation within the South African energy infrastructure sector. However, the need for additional sources of capital (i.e., from international markets or additional local capital formation) to meet the projected annual R100 billion requirement in the long term is acknowledged. The collaboration between the private and public sectors will be critical to ensure that the sector is able to draw on all available sources of capital meaningfully.

Some of the key enablers, catalysts, and innovative funding solutions highlighted in the market sounding include: enhancing the use of blended finance, increasing asset allocations by local pension funds, consistent and transparent implementation of energy infrastructure policies and framework, utilising alternative funding models such as public-private collaboration initiatives, unlocking wider secondary market debt participation, developing a pipeline of bankable projects which ensures consistent deal flow, and facilitating credit enhancement and support from the National Treasury.

Note that the market sounding did not specifically quantify the funding capacity of the Government. Please see Section 6 for a detailed estimation of private and public funding availability and the resultant funding gap.

5.7 Recommendations

Based on the informal feedback provided by the market sounding participants, the following items are critical to address the potential Capex funding gap over the long term for investments in the South African energy infrastructure market:

- Debt funding instruments and products need to be repriced to ensure sufficient liquidity and long-term participation from the secondary debt market, given local commercial bank sector exposure limits and debt holding levels.
- Improved clarity and consistency when implementing programmes to ensure that a consistent pipeline of bankable projects is developed and delivered in the long term.
- The National Treasury guarantees or produces similar guarantee-type vehicles or products to assist in the formation of capital from the private sector and the development of a strong pipeline of bankable projects.
- From a market risk perspective, the development of a wholesale access energy market should be developed to create sufficient liquidity, depth, and pricing certainty, which would encourage additional market participation from power producers, investors, and financial institutions.
- Develop policies, frameworks, and bankable commercial structures with suitable guarantees to encourage the funding and implementation of the transmission programme.
- Reindustrialization and capacitation of technical skills to support the energy infrastructure market, particularly for the EPC contractors and manufacturers.
- Improved coordination between various public stakeholders to ensure projects can progress to bankability and implementation.
- Promotion and education of pension fund management and trustees, relating to alternative asset classes, i.e., the energy infrastructure sector, to encourage the additional formation and allocation of capital.
- Promote innovative funding solutions, including the private funding of transmission, REIT-type vehicles, EPC guarantees, swaps on ZAR-based lending, longer debt tenors, and alternative funding and operating models, e.g., public-private collaboration.

6 Estimating the Energy Infrastructure Funding Gap

6.1 Introduction

Multiple factors present a challenge when determining the funding gap between 2024 and the long-term goal of 2050. Firstly, establishing and quantifying a true, bottom-up baseline is hindered by the limited availability of comprehensive investment data, as well as associated project capital and operating cost information. Furthermore, the funding allocation used in future investment data is not always clearly defined, partly due to limited details regarding the project pipeline. Lastly, the complex makeup of financial structures and funding mechanisms depends on the specific project. When paired with the interplay of global and local economic and associated policy changes, this ultimately results in investment requirement estimations being a moving target.

The Climate Policy Initiative (2023) calculated the most recent and comprehensive estimate of South Africa's climate finance funding gap. According to the estimate, South Africa requires between R334 billion and R535 billion per annum to achieve the NDC by 2030 and Net Zero by 2050. This estimate includes the funding required for all sectors, with the energy sector requiring investment ranges of between R42 billion and R198 billion per annum. To address the issue of data quality and availability, the methodology used to calculate the combined top-down and bottom-up estimates leverages both aggregated funding requirements and project-level data. Project-level data accounted for 92% of the analysis. With the use of unique project identifiers, the double-counting of projects was limited.

To validate these challenges and attempt a bottom-up calculation of the funding gap, an extensive review was conducted of public databases related to funding inventories. The public databases include the Organisation for Economic Co-operation and Development (OECD), World Bank Group, IRENA, GreenCape, and Climate Funds. The datasets analysed are detailed below:

- The OECD (2025) has an interactive database explorer, featuring statistical time series data on a range of topics, including energy and development. The dataset for '*Mobilized private finance for development'* was explored and provides a view of historical investments from multilateral organizations, official donors, and Development Assistance Committee (DAC) countries. The data indicates what the funding is allocated to at a high level, e.g., energy policy, generation, or distribution. However, it is not project specific as it lacks project identifiers and the timeframe spans from 2012 to 2023.
- The World Bank (2025) has a '*Private Participation in Infrastructure (PPI) Project Database'* that allows for customized query searches according to sectors, sub-sectors, countries, type of PPI, and the project status. The historical data segments funding for electricity generation related to

wind and solar greenfield projects, providing project names but not identifiers. The timeframe spans from 2005 to 2023.

- IRENA (2025) has an interactive database, IRENASTAT, which retrieves raw data from the OECD DAC Statistics database and the IRENA Public Finance database, allowing users to select public investments by country, area, technology, and year. Segmented by type of energy source, there is public investment data available for the timeframe 2000 up to 2022.
- GreenCape (2025), a South African non-profit organization (NPO), has a publicly available *Climate Finance Support Database* that includes an extensive list of funds, incubators, and accelerators for the green economy. It does not specify project investments with project identifiers or the relevant period of the investments, but the funders are available.
- The Climate Funds Update (2025) has a publicly available database that presents cumulative data on the recipients of climate finance from multilateral climate funds, allowing the analysis of fund status at an aggregated level. Pledges to the funds can be analysed at a contributor or country level, but without data indicating the recipient. The database also details projects, providing information on the funder, implementing agency, recipient institution, and funding allocation regarding renewable energy generation. This database retrieves raw data from the OECD DAC Statistics database and reflects up to 2023.

In summary, the challenges of quantifying South Africa's energy infrastructure gap are attributed to a lack of adequate forward-looking data, as well as historical data that omits important details, such as project identifiers, names, or descriptions of funding allocation. These databases only indicate at a high level whether the funding was related to energy generation or distribution, without specifics related to capital or operational costs.

Therefore, given these constraints, the methodology adopted in this section uses a combination of top-down and bottom-up assumptions and calculations to estimate the funding gap. These were informed by the literature review and outcomes from the soft market sounding exercise, a review and analysis of current public spending on energy infrastructure (inferred from historical spending data, where possible), and the financing requirement ranges obtained from the technical modelling performed.

6.2 Methodology

The methodology is based on the outcomes of this report's technical modelling component (Section 4), which informed the finance required, and the market sounding component (Section 5), partly informing on the private sector's capacity to provide funding. The methodology is expanded by a high-level review of the potential for public sector funding, as well as other forms of secured funding, over this period.

Overview of the estimation approach

Using the output of the three scenarios between 2025 and 2050 from the technical model, which specifically includes:

- Capex per year, including grid costs, and
- Opex per year, including variable and fixed costs.

While the operational costs are indicated in the final calculations, they do not form part of the calculation of finances required, as this is accounted for by adequate tariff setting and collections. While operational costs will be explored in more detail, note that the focus in this section is on the Capex funding gap.

The Capex funding gap is estimated as the difference between the capital requirement scenario and the estimation of available funding from public and private sources over three defined periods as follows:

- Period 1: 2025 to 2027 [3 years],
- Period 2: 2028 to 2030 [3 years], and
- Period 3: 2031 to 2050 [20 years].

Public sector expenditure on clean energy and electricity: a global and local perspective

The World Energy Investment report published by the IEA (2023) highlighted that investment in clean energy must rapidly increase to meet future energy demands. Subsequently, investment in clean energy has increased, but not proportionately, with a minority of developed countries accounting for the rapid rise (IEA 2023). To illustrate this disparity, the IEA (2023) reports that developing and emerging economies account for only one-fifth of global clean energy investment, despite accounting for two-thirds of the global population. The report estimates that investment in these economies needs to increase by more than seven times to meet the Net Zero by 2050 target. The World Bank (2022) estimates that low- and middle-income countries require an annual energy infrastructure investment of at least 2.8% of their GDP, with 2.2% for capital investment and 0.6% for operational and maintenance investment.

South Africa's public sector capital infrastructure spending averaged 3.58% of the GDP between 2020 and 2023. As a proportion of this, public sector energy infrastructure investment has averaged 0.62% of the GDP (National Treasury, 2024). The National Treasury (2024) estimated in the budget review that public sector expenditure on energy infrastructure in the medium term (2024 to 2026) will increase to an average of 0.87% of the GDP.[35] Considering that South Africa's public sector energy infrastructure

[35] *At an average nominal GDP growth rate of 5.67% over 2024 to 2026*

investment allocation does not specifically proportion spend towards electricity infrastructure, this proportion is assumed to be 70%. If 70% of public sector energy expenditure is directed to electricity infrastructure, this equates to 0.63% of the GDP by 2026. Public sector electricity investment expenditure is therefore estimated to be an average of R45 billion annually over this three-year period (in 2024 real terms).

As indicated in Section 4.6.5.4, the TDP 2024 requires an estimated capital investment of R112 billion in the first five years, of which 80% (R85.6 billion) is estimated for the capacity expansion portfolio, including environmental assessments, land, and servitudes acquisition. The TDP 2024 indicates that an adequate capital budget (R112 billion) has been approved and secured for the first five-year period of the TDP, but that the bulk of the capital spend is expected in the later five-year period (Eskom-NTCSA, 2024a).

The NTCSA acknowledges that its capital plan is limited by its balance sheet and allowable revenue stream and has engaged with the National Treasury to resolve the medium- to long-term challenges. The NTSCA is also exploring alternative funding models, such as:

- Private Sector Participation through ITPs,
- Hybrid delivery models such as Engineering, Procurement, and Construction Management (EPCM), Engineering, Procurement, and Construction (EPC), and owner's engineer approaches, and
- Cost-reflective tariff structures and capitalization policies to ensure financial sustainability.

However, from these statements, it remains unclear how much of the funding will need to stem from public sector funding (Eskom-NTCSA, 2024a). Note that a pilot ITP project is being developed in collaboration with the Ministry of Electricity and Energy and the National Treasury to test private sector involvement.

During this same period, Eskom's obligations related to debt service costs, other operating and maintenance costs, as well as potential future costs to ensure the decommissioning and adaptation of current coal plants, need to be considered. In addition, the current restriction placed on Eskom by the National Treasury (2023) as part of the Eskom Debit Relief package prevents any greenfield investment in energy generation capacity up to 2026. The restrictions only allow the expansion of transmission and distribution capacity.

The World Bank (2023b) reported that 94% of rural South Africa has access to electricity as of 2023. The methodology used to support this quantification relies on nationally representative household surveys and census data. The primary measure is assessed based on whether households report having an electricity connection in the household, but it does not assess the quality, reliability, or affordability of that access. The extent of energy poverty, where electricity is available but not affordable or reliable enough for meaningful use, cannot be quantified based on this methodology. The public sector’s electricity infrastructure spending must include ensuring that South Africans in rural areas gain full access to electricity. However, access to electricity should also be improved at a user level, which would require adopting the World Bank’s multi-tiered framework methodology to measure access.

The indication by the TDP 2024 of secured capital for transmission lines expansion is noted, despite potential implementation risks. However, given the other constraints discussed, only 10%, or R4.5 billion (in 2024 real terms), of the current Eskom budget is spent on new transmission and distribution infrastructure. Beyond 2026, that estimated 10% could potentially increase should the NTCSA strengthen its balance sheet and meet the obligations of the Eskom Debit Relief package. However, municipal compliance with the programme has been low, with only 10 municipalities honouring their current accounts by November 2024, which represents only 2% of the arrear debt balance (Eskom, 2024b).

While this situation could change in the future, significant private sector investment is required to meet the total annual capital investment requirements to fund the JET IP between 2024 and 2050, compared to public sector investment. Furthermore, private sector investment will likely be allocated towards energy investments that have sizable benefits. Therefore, to incentivize investment, there is an urgent need for public-private partnerships and blended finance instruments that enable catalytic investments from the public sector and translate into quick wins and sizable benefit transformations. Internationally, this takes the form of the ITPs previously mentioned, or concessions.

International Partners Group (IPG) grant

The Climate Funds Update (2025) established a database that consolidates cumulative data on the recipients of climate finance from multilateral climate change funds, including the Clean Technology Fund (CTF) and the Global Environment Facility (GEF5). Filtering by recipient (South Africa) and related sub-sector (energy generation, distribution, and efficiency, for renewable sources, such as solar, wind, and biomass), the amount of funding approved for South Africa between 2009 and 2019 for distinct projects totalled USD 576 million, of which USD 528 million concessional loans, and the remaining USD 48 million, was in the form of grants.

The Presidency (2023) published an estimation for financing the JET IP for 2023 to 2027. The financing target of R1 030 billion for the transformation of the electricity sector still requires R315 billion (30%) as an outstanding funding gap. The JET IP indicates that the remaining R715 billion (70%) would need to stem from a combination of funding sources, including public DFIs and multilateral development banks (R100 billion), the private sector (R500 billion), and IPG grants (R115 billion).

Formally, USD 6.9 billion (R103.5 billion) of the total allocation is towards electricity infrastructure from 2023 to 2027 as stipulated in the JET IP 2023–2027 (The Presidency, 2023). However, this analysis shows that only 15% of these funds are allocated directly to Capex for new power generation, transmission, and distribution capacity. Following the withdrawal of the US commitment in early 2025, the European Union (EU) has announced that it will intervene to address the gap, pledging an investment package of EUR 4.7 billion (approximately USD 5.1 billion) to support South Africa's green energy transition. This funding will support various projects, including renewable energy initiatives, green hydrogen production, and critical infrastructure development (ESI Africa, 2025).

Estimated private finance availability

As a starting point, the notional average annual amount of R100 billion from the market sounding component of this report was utilised. This approximated the financial requirements stipulated in the Draft IRP 2023 report. Based on the market sounding output, South Africa should not experience a funding gap in the short term. However, it can expect to experience a funding gap after 2027, primarily due to the lack of project pipelines that can be developed into bankable opportunities and other attractive financing opportunities. This lack of bankable opportunities deters private investment.

Given these time horizons, and maintaining the five-year increments (2025, 2030, 2035, and so forth until 2050) from the technical modelling, the funding gap is represented over three periods:

- Period 1: 2025 to 2027 [3 years],
- Period 2: 2028 to 2030 [3 years], and
- Period 3: 2031 to 2050 [20 years].

These three periods are significant to the funding gap calculations. From 2028 to 2030 and 2031 to 2050, high-funding attraction and low-funding attraction alternatives are introduced (with varying associated assumptions) to allow flexibility in the results. Specifically, this allows for a quantitative view of the expectation among market sounding participants that a gradual to significant funding gap will appear over time.

A literature review established that the PCC quantification of funding received follows the report and associated methodology published by the PCC (2023a) on the South African Climate Finance Landscape. An average of R131 billion from 2019 to 2021 is reported from public and private sources for mitigation, adaptation, and dual-benefit uses. Segmented for clean energy and energy-efficiency investment only, the R131 billion reduces to R102 billion. Furthermore, the Climate Policy Initiative’s quantification of funding for periods 2017 to 2018 and 2019 to 2021 is assumed to include the funding recorded in the Climate Funds Update database (2024). Lastly, in addition to the amount of R102 billion, the IPG loan of R5 billion per annum from 2024 to 2026 is recognised, considering that the pledge came after the Climate Policy Initiative's calculation of funding received for clean energy and energy-efficiency investment only. By adjusting the R102 billion (in 2021) for inflation to reflect 2024 real terms, the amount comes to R118 billion.

Regarding tariffs

As another stream of funding, electricity output multiplied by the average electricity tariff was used to calculate an annual electricity revenue. Coming into effect on 1 January 2025, the Electricity Regulation Amendment Act 38 of 2024 has set new provisions relating to electricity tariffs and price-setting methodologies for licensees (RSA, 2024). The new provisions, as well as the preceding regulations around price setting, must be followed by NERSA, which ultimately approves all electricity tariffs. The regulatory oversight offered by NERSA ensures that all electricity tariffs are set at margins that can support the recovery of capital, operational, and maintenance costs, which must be expressed in terms of a unit cost per kWh delivered from the power station (NERSA, 2021). These costs include:

- **Capital cost to generate power and equipment used:** This includes land acquisition costs, construction costs associated with building physical infrastructure, and equipment purchases essential for power generation, such as generators, turbines, transformers, and control systems.
- **Cost of fuel burned:** This varies per energy technology, with solar, wind, and hydroelectric having minimal or zero fuel costs.
- **Cost of operating and maintaining the power station or plant:** This includes maintenance, labour, and administrative expenses.

The government entities and associated municipalities are not allowed to make a profit through the sale of electricity, in accordance with the Municipal Systems Act of 2000 and the Municipal Finance Management Act of 2003. Further, as guided by the National Treasury (2023), Eskom's Capex is restricted to transmission and distribution only, while the Eskom Debit Relief period is active. Therefore, any surplus or profit arising from public sector electricity sales will not be used to fund greenfield infrastructure projects related to energy generation and will be limited in its ability to fund greenfield infrastructure projects related to transmission and distribution. Furthermore, the Government needs to make financial provisions for the adaptation and decommissioning of coal plants, although investment will be required from both the public and private sectors.

However, the new provisions affect private companies differently, which can incentivise additional funding from the private sector. Private companies selling electricity will be able to make a profit should

NERSA approve reasonable tariff margins that allow the full recovery of investment costs, while remaining fair for the consumer. However, this does not guarantee reinvestment by the private company into new energy generation or transmission infrastructure.

While Eskom does earn income from tariffs, it is owed R110 billion by municipalities, who in turn are owed approximately R350 billion by ratepayers (BusinessLive, 2024). This restricts Eskom's ability to reinvest tariff revenue into new energy infrastructure. Tariffs are therefore not included as a source of finance for new energy generation, transmission, and distribution infrastructure in the funding gap calculation.

6.3 Assumptions and Limitations

The assumptions applied for the funding gap calculations are as follows:

- **Discount rate applied:**
  - In line with the technical modelling conducted in Section 4, a discount rate of 8% over the forecast period to 2050 was applied to reflect 2024 real term figures.
- **Economic growth:**
  - Nominal GDP growth of 5.5% in 2024 and 2025, 6.0% in 2026 and 2027, and 6.5% from 2028 to 2050.
  - Real GDP growth of 1.0% in 2024 and 2025, 1.5% in 2026 and 2027, and 2% from 2028 to 2050.
- **Public sector funding:**
  - Total nominal budget spending increase per annum remains 4.62%, based on the annual average increase of 2024, 2025, and 2026 until 2050.
  - Public spending on energy as a proportion of total government spending remains flat at 2.88% until 2050. This is based on the proportional spend in 2026 of the National Treasury medium-term budget for 2024.
  - The proportion of energy spending allocated to energy generation, transmission, and distribution is assumed to be 70% and remains constant until 2050. This equates to an average of R45 billion from 2024 to 2026.
  - Energy spending as a proportion of the nominal GDP will increase from 0.80% in 2024 to 0.91% in 2025 and remain at this level until 2050.
  - Electricity spending as a proportion of nominal GDP is therefore 0.56% in 2024 and increases to 0.64% in 2025 until 2050.
  - The estimated proportional spend on new power generation, transmission, and distribution is 10% of total electricity spend from 2025 to 2027 (R4.5 billion on average) and 15% from 2028 to 2030 (R7.5 billion on average). From 2031 to 2050, this increases to 20% (averaging approximately R10 billion per annum).

- **Private sector funding:**
  - Using the annual tracked finance of R102 billion per annum from 2019 to 2021 for South Africa as a basis for estimating its value in 2024, a 5% inflation rate is applied per annum to arrive at R118 billion of private sector funding available.
  - For 2025–2027, the figure of R118 billion is applied for both the low and the high funding attraction alternatives. The high and low funding attraction alternatives are not applied to avoid further distorting the short-term view from the range provided by the technical modelling scenario outputs.
  - For 2028–2030, in the low funding attraction alternative, it is assumed that 67% of the R118 billion can be secured, i.e., R79 billion. In the high funding attraction alternative, it is assumed that 75% of the R118 billion can be secured, i.e., R89 billion.
  - For 2031–2050, in the low funding attraction alternative, it is assumed that 50% of the R118 billion can be secured, i.e., R69 billion. In the high funding attraction alternative, it is assumed that 60% of the R118 billion, i.e., R81 billion can be secured.
- **IPG loans:**
  - Through an extensive review of the JET IP funding allocations, R5 billion (in 2024 real terms) of funding per annum between 2025 and 2027 towards new power generation, transmission, and distribution is assumed. The EU’s additional funding pledge is assumed to replace the US’s cancelled portion. The IPG loan was only announced after the R118 billion private sector funding had been calculated by the Climate Policy Initiative (2023) and was therefore not included in this amount.
  - In addition, the Climate Policy Initiative funding calculations from 2017 to 2018 and 2019 to 2021 are assumed to represent the funding recorded in the Climate Funds Update database (2024).

The estimated annual average funding availability over the three periods is summarised in Table 32.

Table 32: Funding Attraction Alternatives per Period (R'bn p.a., in 2024 real terms)

2025–2027	Low	High
Private	118.1	118.1
Public	4.5	4.5
IPG loan	5.0	5.0
Total	127.6	127.6
2028–2030	**Low**	**High**
Private	79.1	88.6
Public	7.5	7.5
Total	86.6	96.1
2031–2050	**Low**	**High**
Private	59.0	70.8
Public	10.0	10.0
Total	69.0	80.8

- **Tariffs:**
  - Tariffs should allow the recovery of Opex and repayment of Capex over the determined period, plus a specific margin in the case of private sector funding.
  - However, there is no guarantee that private companies will reinvest tariff revenue into new energy generation or transmission infrastructure.
  - Even with funding from the National Treasury and tariff revenue, the following areas place a burden on Eskom's finances:
    - Current debt burden (including money owed by municipalities and rate payers),
    - Funding requirements for operations and maintenance (O&M) on its current coal fleet, and
    - Costs associated with the decommissioning and/or retrofitting of coal plants.
  - As a result of this, tariffs are not included as a finance source for new energy generation, transmission, and distribution in the funding gap calculation.
- **Technical modelling outputs applied:**
  - The technical modelling was conducted in tranches of five years across the three scenarios. The annual average Capex and Opex were applied from 2025 to 2030 in two funding gap periods from 2025 to 2027 and 2028 to 2030. While the annual average costs for Capex and Opex from 2031 to 2050 were applied to the third period to allow more specificity per period (i.e., the short- and medium term versus the longer term).[36]

[36] *The exception to using specific averages from 2025 to 2030 and 2031 to 2050 is the grid costs. For these costs, a straight average over the period from 2025 to 2050 was applied, as this is how the output was received in the technical modelling output.*

- Table 33 provides a summary of the technical modelling results utilized in the funding gap estimations.

Table 33: Technical Model Annual Average Finance Requirement Summary (R'bn p.a., 2024 real terms, and % of GDP)

Scenarios		Scenario A (Green Industrialization)		Scenario B (Market Forces)		Scenario C (Business-as-usual)	
Average annual cost detail		2025–2030	2031–2050	2025–2030	2031–2050	2025–2030	2031–2050
Capex	Generation	125.3	44.9	59.1	43.7	80.6	48.1
	Grid	14.7	14.7	10.1	10.1	8.9	8.9
	Total	140.1	59.7	69.2	53.8	89.4	57.0
	% of GDP	1.9%	0.8%	0.9%	0.7%	1.2%	0.8%
Opex	Variable cost	70.4	15.2	89.1	49.3	112.7	56.9
	Fixed costs	54.1	25.0	49.8	17.3	50.1	18.8
	Total	124.5	40.3	138.9	66.6	162.8	75.6
	% of GDP	1.7%	0.5%	1.9%	0.9%	2.2%	1.0%
Combined	Grand Total	264.5	100.0	208.1	120.4	252.2	132.6
	% of GDP	3.6%	1.4%	2.8%	1.6%	3.4%	1.8%

The study is limited by the absence of comprehensive forward-looking data and the lack of detailed historical data. This data fails to include specific project identifiers, names, or descriptions of funding allocations. Instead, it provides high-level categories related to energy generation or distribution without detailed capital or operational cost information.

6.4 Results

The outputs are presented below in 2024 real terms for the three energy scenarios and the high and low Capex funding attraction alternatives over the three periods. All Capex (including grid costs), Opex (fixed and variable costs) are included, as well as a Capex funding gap estimate.

Table 34 captures the various Capex funding gap estimations of the three scenarios and funding attraction alternatives. The average annual Capex requirement estimations per scenario for the two periods from 2025 to 2030 and 2031 to 2050 are highlighted in the first rows. This is followed by the Capex secured and Capex gap for each period, scenario, and funding attraction alternative. For clarity, Scenario A relates to the Green Industrialization scenario, Scenario B to the Market Forces scenario, and Scenario C to the Business-as-usual scenario.

Table 34: Capex Funding Gap Estimations per Scenario and Funding Attraction Alternatives (R'bn p.a., 2024 real terms, and % of GDP)

	Scenario A (Green Industrialization)		Scenario B (Market Forces)		Scenario C (Business-as-usual)	
Capex requirement 2025–2030	140.1		69.2		89.4	
Capex requirement 2031–2050	59.7		53.8		57.0	
2025–2027	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**
Capex secured	127.6		127.6		127.6	
Opex	124.5		138.9		162.8	
Capex gap	12.5		-58.4		-38.1	
Gap % of GDP	0.17%		-0.80%		-0.52%	
2028–2030	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**
Capex secured	86.6	96.1	86.6	96.1	86.6	96.1
Opex	124.5	124.5	138.9	138.9	162.8	162.8
Capex gap	53.5	44.0	-17.4	-26.9	2.8	-6.6
Gap % of GDP	0.73%	0.60%	-0.24%	-0.37%	0.04%	-0.09%
2031–2050	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**
Capex secured	69.0	80.8	69.0	80.8	69.0	80.8
Opex	40.3	40.3	66.6	66.6	75.6	75.6
Capex gap	-9.4	-21.2	-15.3	-27.1	-12.1	-23.9
Gap % of GDP	-0.13%	-0.29%	-0.21%	-0.37%	-0.16%	-0.33%

For the first period, from 2025 to 2027, a high and low funding attraction alternative was not calculated to avoid distorting the short-term view further from the range provided by the technical modelling scenario outputs. During this period, Scenario A (Green Iindustrialization) has an annual average funding gap of R12.5 billion (0.17% of GDP), with no funding gap in Scenario B (Market Forces) and Scenario C (Business-as-usual). This is depicted in Figure 51.

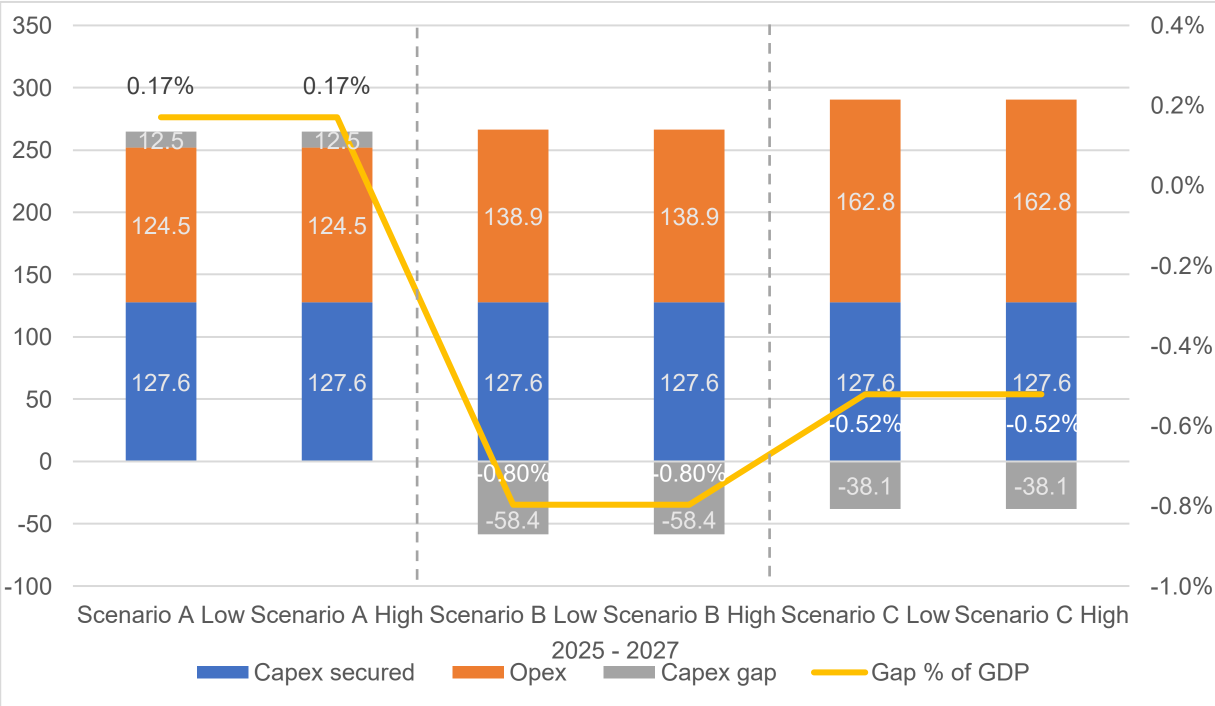

Figure 53: Capex Secured, Opex, and Capex Gap from 2025 to 2027 (R'bn p.a., 2024 real terms)

From 2028 to 2030, the funding gap estimates increase for Scenario A (Green Iindustrialization) compared to the previous period. This is mainly due to the assumption that private sector funding availability will diminish under both low (securing only 67% of the 2025 to 2027 period funding) and high (securing 75%) funding attraction alternatives, while high levels of Capex outlays are required during this period. Despite the assumption regarding reduced private sector funding availability compared to the previous period, there is only an annual funding gap of R2.8 billion under the low funding attraction alternative for Scenario C (Business-as-usual) and no funding gap under the high funding attraction alternative for Scenario C (Business-as-usual), with no funding gap under Scenario B (Market Forces). This is shown in Figure 52.

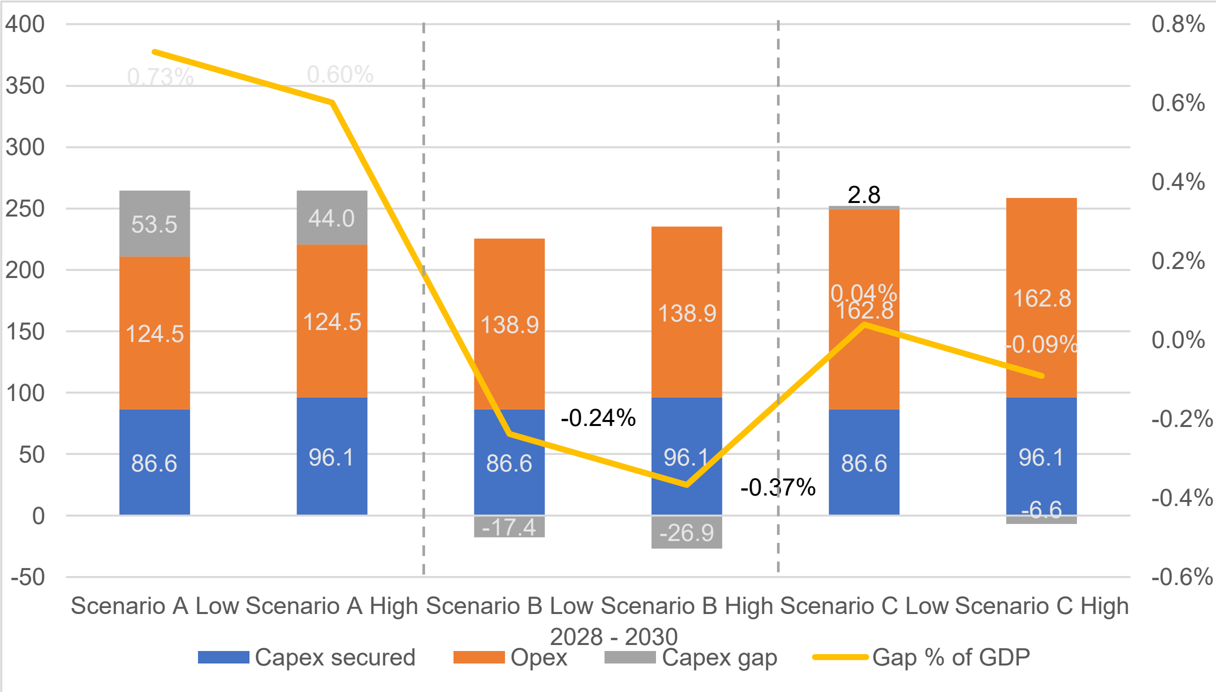

Figure 54: Capex Secured, Opex, and Capex Gap from 2028 to 2030 (R'bn p.a., 2024 real terms)

From 2031 to 2050, despite the assumption of reduced private sector funding to a range of 50 to 60% of the funding levels available during the 2025 to 2027 period, there is no funding gap for any of the three scenarios. See Figure 53.

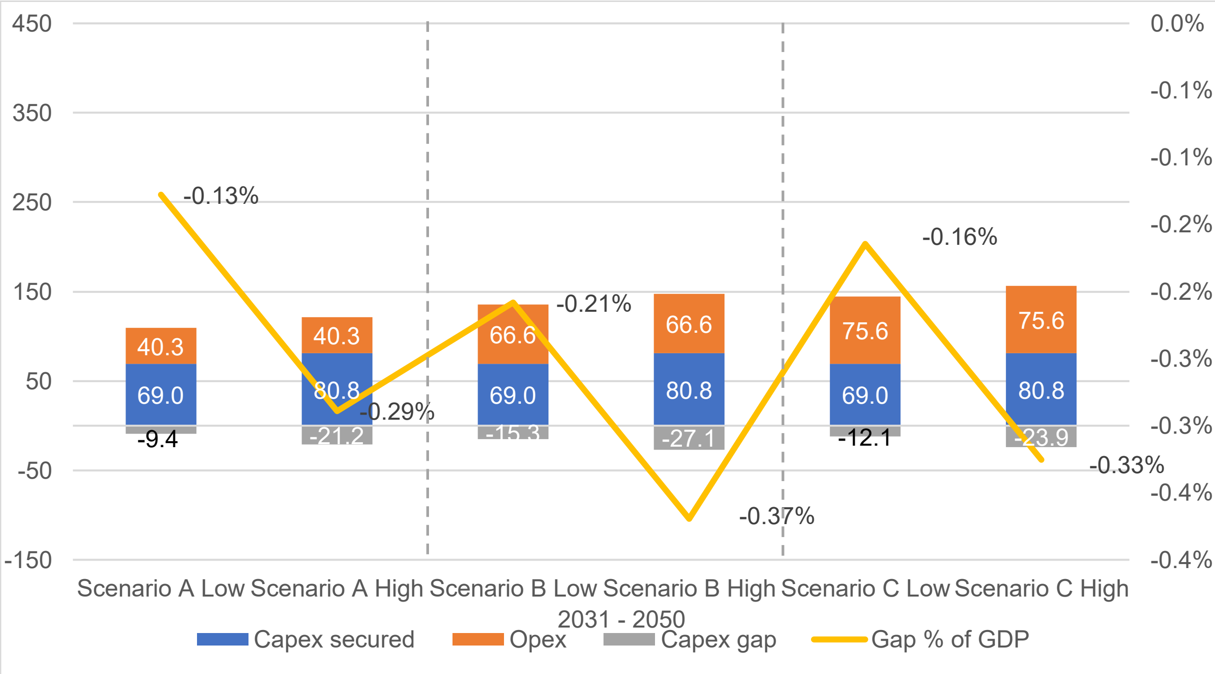

Figure 55: Capex Secured, Opex, and Capex Gap from 2031 to 2050 (R'bn p.a., 2024 real terms)

6.5 Discussion

To address the funding gap question, insights from the soft market sounding exercise, current public and private spending on energy infrastructure, and the Opex and Capex financing requirement ranges from the technical model were examined.

Informed by the outcomes of the market sounding exercise, calculations for the three scenarios were made over three periods (2025 to 2027, 2028 to 2030, and 2031 to 2050), with a high and low funding attraction alternative for periods two and three reflecting two trajectories of lower private sector funds secured for capital when compared to the first period. This was due to the participants indicating that they expect private sector funding to be at adequate levels in the short term (2025 to 2027) with an annual average of R100 billion used as the notional figure, but that this would reduce in the medium term (2028 to 2030) and reduce again thereafter (2031 to 2050) to below what would be required. The Capex calculations include grid costs, while the Opex costs include variable and fixed costs. All figures are presented in 2024 real terms.

In summary, the average annual funding gap range for Capex per period across the three scenarios is highlighted in the table as follows:

Table 35: Capex Gap Summary per Scenario and Funding Attraction Alternatives (R'bn p.a., 2024 real terms, unless indicated otherwise)

	Scenario A (Green Industrialization)		Scenario B (Market Forces)		Scenario C (Business-as-usual)	
2025–2027	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**
Capex gap	12.5		-58.4		-38.1	
Gap % of GDP	0.17%		-0.80%		-0.52%	
2028–2030	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**
Capex gap	53.5	44.0	-17.4	-26.9	2.8	-6.6
Gap % of GDP	0.73%	0.60%	-0.24%	-0.37%	0.04%	-0.09%
2031–2050	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**
Capex gap	-9.4	-21.2	-15.3	-27.1	-12.1	-23.9
Gap % of GDP	-0.13%	-0.29%	-0.21%	-0.37%	-0.16%	-0.33%
Total Capex gap	197.9	169.6	0	0	8.5	0

Given that the assumptions relating to the high and low funding attraction alternatives are the same for each scenario under each period, the extent of the funding gap differences is directly determined by the Capex requirements. Specifically, the timing of the Capex outlay requirements for the underlying technology mix and the associated learning rates of these sets of technologies. Given the assumptions, Scenario B (Market Forces) shows the lowest overall Capex funding gap risk, with Scenario C (Business-as-usual) only indicating a marginal funding gap under the low investment attraction alternative during 2028 to 2030. However, Scenario A (Green industrialization) does show a funding gap from 2025 to 2030 as the annual average Capex outlay is much higher than the others during this period. This could potentially challenge the country's ability to secure these levels of funding in the short to medium term if adequate levels of private sector funding cannot be maintained.

The Capex funding gap estimations rely on the assumption that effective tariff setting and collections ensure that operational and maintenance spending is recovered in addition to the repayment of Capex over the predetermined period (i.e., the WACC).

On 30 January 2025, NERSA approved increases of 12.7% (2025/26), 5.36% (2026/27), and 6.19% (2027/28) in each of the next financial years. This is much lower than Eskom's application for tariff increases of 36% on 1 April (2025/26), 11.81% (2026/27), and 9.1% (2027/28) (Moneyweb, 2025).

While the tariff setting process includes various considerations, including consumer affordability, there is a distinct risk that the funding gap could grow wider if Eskom cannot collect sufficient revenue to recoup costs associated with its capital cost to generate power and equipment used, cost of fuel burned, and cost of operating and maintaining these new power stations. The same applies to the NTCSA with respect to expanding, operating, and maintaining the transmission system.

Regarding collections, as previously noted, Eskom continues to struggle with the non-payment of approximately R110 billion in debt, which could further exacerbate the long-term funding gap.

When including Opex in this equation, a funding gap exists for all scenarios, ranging between 1.10% and 1.87% of the GDP from 2025 to 2027 and 1.53% and 2.43% of the GDP from 2031 to 2050. From 2031–2050, Scenario A's Opex is lower than the Opex of the other two scenarios, which leads to this scenario having the lowest total funding gap from 2031 to 2050. This is captured in Table 36.

Table 36: Capex and Opex (Total) Gap Summary per Scenario and Funding Attraction Alternatives (R'bn p.a., 2024 real terms, and % of GDP)

	Scenario A (Green Industrialization)		Scenario B (Market Forces)		Scenario C (Business-as-usual)	
2025–2027	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**
Total gap	137.0		80.5		124.6	
Gap % of GDP	1.87%		1.10%		1.70%	
2028–2030	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**
Total gap	177.9	168.5	121.5	112.0	165.6	156.1
Gap % of GDP	2.43%	2.30%	1.66%	1.53%	2.26%	2.13%
2031–2050	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**
Total gap	30.9	19.1	51.4	39.6	63.6	51.8
Gap % of GDP	0.42%	0.26%	0.70%	0.54%	0.87%	0.71%

The calculations are very specific to new energy generation, transmission, and distribution infrastructure and therefore cannot be directly compared to many other studies. While most studies provide estimates on the funding required to build new power generation, transmission, and distribution infrastructure, they do not indicate a specific funding gap.

However, from the literature review, the JET IP indicates an estimated financing gap for the electricity commitment of R315 billion (USD 21 billion) or around 25% against the total investment required by the JET IP between 2023 and 2027.

The PCC (2023b) shows that South Africa's climate finance needs must increase by three to five times to achieve the country's climate objectives, which are related to the NDC targets, and the net-zero ambition by 2050. The PCC estimates that a funding gap of R203 billion to R404 billion per annum is outstanding and needs to be addressed to meet the NDC goals. However, this needs qualification as it extends beyond new power generation, transmission, and distribution infrastructure requirements. The PCC (2023c) found that within the energy sector, the annual investment requirement estimates range from a minimum of R42 billion to a maximum of R198 billion, with an average annual investment need of R111 billion. The study stopped short of attributing an estimated funding gap directly to the energy sector.

The NBI reports that while approximately R70 billion (USD 4.67 billion) per annum has already been mobilized for energy sector transformation, an average gap of R140 billion (USD 9.33 billion) per annum must be closed to fund the technical mitigation investment in the transition to 2050 (NBI, 2022). While this estimate is higher than our Capex funding gap calculations, the estimate accounts for investment beyond energy infrastructure without allocating a specific funding gap.

6.6 Conclusion

The Capex funding gap estimations suggest that, due to the high Capex requirements from 2025 to 2030, a notable Capex funding gap could exist under Scenario A (Green Industrialization). However, from 2031 to 2050, no funding gap exists for Scenario A (Green Industrialization). Scenario C (Business-as-usual) could see a marginal funding gap from 2028 to 2030. Furthermore, no funding gap exists for Scenarios B (Market Forces) over the forecast period or for Scenarios C (Business-as-usual) from 2025 to 2027 and again from 2031 to 2050, provided adequate levels of private sector funding can be secured over the forecast period.

These Capex funding gap estimations rely on effective tariff setting and collections. If Eskom and the NTCSA cannot collect sufficient revenue to recoup the costs associated with their required expansions, as well as the operation and maintenance of new energy generation and transmission, the funding gap could increase.

Furthermore, careful consideration must be given to the risks inherent in the economic growth projections and corresponding public funding assumptions, alongside potential variances between project-specific discount rates and the 8% general discount rate applied in these estimations. Any deviation from these foundational assumptions could materially impact the country's capacity to adequately finance the energy futures envisioned across these scenarios.

This analysis indicates that the available public energy infrastructure spending and Eskom tariff revenues alone will not be sufficient to finance the required new energy generation, transmission, and distribution infrastructure. Therefore, funding must be sourced from the private sector, including donor funding.

The market sounding participants indicated that regulatory and project supply challenges could lead to a decline in private sector funding in the medium to long term. The Capex funding gap will therefore depend on how effectively South Africa can reform its local energy regulation and market and ensure a supply pipeline of energy infrastructure projects that are attractive investments.

6.7 Recommendations

Overarching interventions to secure additional private sector funding include:

1) Expediting regulatory and market reform,

2) Re-examining mechanisms for developing and attracting the necessary technical and deal-making skills to allow additional, investment-attracting project pipelines beyond the short term, and
3) Effectively and strategically using (catalytic) public sector funding and guarantees to increase project attractiveness by reducing risk.

These interventions, combined with a predictable regulatory environment, can increase investor confidence, and attract additional capital through public-private partnerships, blended finance, international aid, and donor funding.

7 Policy and Regulatory Review

7.1 Introduction

The purpose of this regulatory review is to identify and highlight the main strengths and gaps of the policy and regulatory framework currently in force relating to funding energy infrastructure in South Africa. It further aims to provide concrete recommendations for regulatory improvement and reform to achieve a competitive, resilient, and sustainable electricity sector, based on estimates of the funding gap and technical modelling as outlined in previous sections.

7.2 South African Analysis

7.2.1 The Constitution of South Africa

The Constitution does not mention the adoption of renewable energy or its associated infrastructure, nor is there an explicit right to electricity in the Constitution. However, the right to access to electricity is implicit when considering the right to housing as set out in Section 26 of the Constitution. From a Bill of Rights perspective, access to electricity is considered a condition for exercising other rights, including human dignity, adequate housing, water, and health care.

Section 24 of the Constitution enshrines the right to a healthy environment and mandates the state to protect the environment for the benefit of present and future generations. This includes taking reasonable legislative and other measures to:

- Prevent pollution and ecological degradation,
- Promote conservation, and
- Secure ecologically sustainable use of natural resources and development, while promoting justifiable economic and social development.

Renewable energy plays a crucial role in achieving these goals by reducing pollution and ecological degradation, conserving natural resources, and supporting sustainable development. By transitioning to renewable energy sources, such as solar, wind, and hydro power, South Africa can reduce its reliance on fossil fuels, which are major contributors to environmental pollution and climate change.

Section 153 of the Constitution places the responsibility on municipalities to ensure the provision of services to communities in a sustainable manner and to promote economic and social development. This obligation echoes Section 237 of the Constitution, which provides that "[a]ll constitutional obligations must be performed diligently and without delay." These services include electricity reticulation and provision and are therefore an important funding source for local governments, particularly for larger urban municipalities. As such, the Government must have the necessary legislation and policies in place to achieve the constitutional provisions related to electricity delivery. Some of the laws and policies adopted are discussed in the tables below as they pertain to the financing and deployment of energy infrastructure.

7.2.2 South African Energy Policies and Laws

Table 37: South Africa's Energy Policies

Policy	Provisions in policy relating to the financing of energy infrastructure
The White Paper on the Energy Policy of the Republic of South Africa of 1998	This White Paper on energy policy is an overarching document that sets out official Government policy on the production, distribution, and consumption of energy. In a general sense, it represented, for the first time, a comprehensive perspective of South Africa's official overall energy needs and options. This laid the foundation for energy laws such as the National Energy Act and the Electricity Regulation Act. The initial commitment to renewable energy technologies outlined in this document was supplemented by a specific policy document on renewable energy, known as the White Paper on Renewable Energy, published in 2003. The white paper also discusses the development of a national electrification strategy. The Government will ensure the allocation of funds for addressing backlogged electrification projects and will aid in subsidizing infrastructure development and electrification projects. Utilities are expected to fund these projects from a combination of commercial finance, concessionary loans, and grant funding. The government will differentiate between electrification addressing backlogs and electrification as part of new infrastructure development for funding purposes.[37] Furthermore, the white paper acknowledges that unless alternative funding and pricing mechanisms are developed, the industry will be unable to both fund electrification and contribute to other municipal services without substantial increases in tariffs, major reductions in distribution costs, or the curtailment of the electrification programme. The entire industry (generation, transmission, and distribution) must move to cost-reflective tariffs with separate, transparent funding for electrification and other municipal services. [38] While this white paper dates to 1998, its principles are echoed in the current transition in the South African energy sector, and its aims remain relevant for guiding the process of liberalization.
The South African Renewable Energy	The South African Cabinet adopted the South African Renewable Energy Masterplan (SAREM) on 28 March 2025. It aims to industrialize and localize the renewable energy

[37] *See pp. 48 of the White Paper on the Energy Policy of the Republic of South Africa of 1998.*
[38] *See pp. 48 of the White Paper on the Energy Policy of the Republic of South Africa of 1998.*

Policy	Provisions in policy relating to the financing of energy infrastructure
Masterplan (SAREM) (adopted by cabinet on 28 March 2025)	value chain in South Africa, driving economic growth and fostering inclusive development. It outlines strategies to support local demand, enhance industrial capabilities, and ensure a just transition for all societal segments. The plan focuses on leveraging the rising demand for renewable energy and storage technologies to achieve energy security and the SDGs by 2030. The SAREM includes several funding recommendations to support the deployment and development of renewable energy infrastructure: • **Transformation Fund:** Set up a Transformation Fund to provide capital, support guarantees, and warranties for emerging suppliers in the renewable energy sector. This fund aims to catalyse existing and additional funding streams and support new entrants into the value chain.[39] • **Strategic Partnership Programme (SPP):** Launch and progressively expand the SPP to incentivize large private-sector enterprises to support and develop the ability of SMMEs within their supply chain. The SPP is a cost-sharing programme designed to encourage collaboration between large companies and small and medium enterprises in the renewable energy and storage value chains. • **Incentives for Local Procurement**: Integrate localization objectives into public procurement programmes from all spheres of government and state organs. Additional support should be awarded to beneficiaries procuring skills technologies locally, ensuring that public policy related to renewable energy and storage aligns with localization goals. • **Tax Incentives**: Re-activate the existing 12i tax allowance incentive with a focus on renewable energy and battery value chains. This incentive provided a tax deduction for qualifying assets and was designed to support both greenfield and brownfield manufacturing investments. • **Support for Energy Security in Industrial Parks**: Provide dedicated support for energy security in industrial parks, including access to incentives for Special Economic Zones and improving the ease of doing business through services like InvestSA's One Stop Shop. • **Public Procurement Rounds**: Launch public procurement rounds for renewable energy and storage in just transition hotspots, leveraging Renewable

[39] *See pp. 50 of the South African Renewable Energy Masterplan (SAREM).*

Policy	Provisions in policy relating to the financing of energy infrastructure
	Energy Development Zones and focusing on regions like Mpumalanga, where additional grid capacity will be released as coal-fired power plants close. • **Inclusive Rollout and Community Projects**: Develop programmes to refurbish and reuse solar panels replaced by IPPs for public and community buildings. Pilot projects for community-owned renewable energy projects and Employee Share Ownership Plans will be explored to scale up interventions for low-income households. • **Environmental, Social, and Governance (ESG) Certification**: Propose fostering ESG certification in the renewable energy sector to attract better funding and support the promotion of decent work in new economic sectors. These funding recommendations are designed to ensure the inclusive and sustainable growth of the renewable energy sector in South Africa, supporting new market entrants, fostering local manufacturing, and promoting economic transformation. However, none of the above initiatives have been formalized or introduced, and the development and implementation of these initiatives would need to be expedited to increase the deployment of renewables as envisioned under the master plan.
National Integrated Energy Plan (IEP) 2016	The development of a National IEP was envisaged in the White Paper on Energy Policy of 1998 and formulated in terms of the National Energy Act. The IEP is the overall energy plan for liquid fuels (petrol, diesel, paraffin), gas, and electricity. The IEP aims to diversify South Africa's energy mix but also recognises that diversification in the energy industry requires time. As such, coal will continue to provide energy in the future, but this will be limited to electricity generation. Coal will, however, be displaced substantially over time by a diverse mix of renewable energy carriers, including solar and wind power. The IEP was published in 2016 and is considered outdated given the technological advancements and funding options that have emerged since its publication. The plan does not outline specific plans for funding electricity infrastructure, but rather highlights certain funding needs. Some of the funding needs include: • More funding should be targeted at long-term research focus areas in clean coal technologies, such as CCS and UCG, as these will be essential in ensuring that South Africa continues to exploit its indigenous minerals responsibly and sustainably. • Adequate funding should be provided to the newly established Department of Mineral and Petroleum Resources and the Department of Electricity and Energy to ensure that their mandates are achieved.

Policy	Provisions in policy relating to the financing of energy infrastructure
	• Continued funding should be provided to ensure the implementation of the INEP and the Universal Electrification Strategy. • Additional funding should be allocated for the development of an Integrated Household Energy Strategy. • Investment in R&D to find innovative means for the beneficiation or recycling of gases emitted during the generation of electricity. • Large investments in transmission lines are necessary from the areas of high radiation to the main electricity consumer centres to enable increased solar deployment. • The current policy and regulatory framework could be developed further, and investment would be needed to develop the policy environment.
Draft Integrated Resource Plan (IRP) 2023	The White Paper on Energy Policy describes Integrated Resource Planning as "a decision-making process concerned with the acquisition of least-cost energy resources, which takes into account the need to maintain adequate, reliable, safe, and environmentally sound energy services for all customers." It is important to take note that the IRP in the South African context is not the National Integrated Energy Plan that sets out South Africa's energy roadmap. The IRP is a National Electricity Plan and is a subset of the National IEP. The draft plan does not contain specific provisions related to the funding of energy infrastructure, but acknowledges the following points: • South Africa must consider investing in cleaner coal technologies, given the country's continued reliance on and abundance of coal. • The facilitation and acceleration of private investment in power generation capacity is crucial. • Eskom's debt must be addressed to liberate much-needed investment in critical transmission and other infrastructure, and ensure proper maintenance of plant and equipment.
Just Energy Transition Investment Plan (JET IP) 2022	The purpose of South Africa's JET IP is to manage the country's transition to a low-carbon economy in a way that addresses economic, social, and environmental challenges. The plan is designed to support the decarbonization of the electricity sector, promote new economic opportunities such as green hydrogen and EVs, and ensure that the transition is just, essentially protecting vulnerable workers and communities affected by the shift away from coal. The plan outlines key mechanisms needed to fund the JET. These include the following:

Policy	Provisions in policy relating to the financing of energy infrastructure
	1) **Grants**: Grants are effective in strengthening the enabling environment for priority sectors and supporting critical initiatives that do not generate revenue, such as policy development, capacity building, sector strategy development, and feasibility studies. As such, grants can create an enabling policy environment to attract additional funding and investment from the private sector. 2) **Concessional loans:** When strategically deployed, concessional financing serves as a catalytic source of funding that can mitigate real and perceived risks, reduce the cost of financing, and attract additional private sector financing to scale up climate finance in critical sectors. This includes expanding the electricity infrastructure and accelerating the development of the EV and green hydrogen sectors. ▪ **Budgetary support:** Budget resources must be used in a targeted manner to signal fiscal support for the transition, address specific barriers, and provide support where other sources of financing may be more difficult to mobilize. ▪ **Blended finance**: Blended finance currently represents a small share of South Africa's climate finance supply and will need to be significantly expanded to fully unlock the potential of concessional funding. 3) **Thematic bond issuance:** Instruments such as green bonds, transition bonds, or resilience bonds are increasingly gaining prominence in supporting sector-specific activities. They offer long-term maturities and predictable returns at a slight discount to the market based on the defined impact metrics, making them particularly attractive to institutional investors, such as pension funds. 4) **Market-related funding instruments:** Market-related instruments include risk-mitigation instruments, such as guarantees that can facilitate private sector participation; venture capital that provides capital and technical assistance to early-stage businesses, often in innovative technology-related sectors to accelerate growth and scale; and equity as a source of subordinated, risk-sharing capital that can accelerate growth and make additional funds available for JET IP-related projects or businesses.
Low Emissions Development Strategy 2020	The South African Low Emissions Development Strategy provides limited but notable provisions for the funding of energy infrastructure. The strategy recognises the need for significant investment in energy infrastructure to support the transition to a low-

Policy	Provisions in policy relating to the financing of energy infrastructure
	emission economy. It highlights the role of public-private partnerships in mobilizing funding. The document mentions potential Government funding through national budgets, grants, and subsidies, and emphasises the role of state-owned enterprises (SOEs), particularly in the electricity sector, in driving infrastructure expansion. The strategy acknowledges the importance of International Climate Finance in supporting the transition to a low-carbon economy. It provides a roadmap for leveraging funding from the GCF, GEF, and DFIs to finance large-scale renewable energy projects, improve grid infrastructure, and support sustainable industrial development. However, the strategy also highlights the need for institutional improvements and strategic partnerships to access and deploy these funds effectively. The document also stresses the importance of climate-focused pricing regimes that could encourage private sector investment in renewable energy. This includes carbon pricing and green bonds to attract private sector investment. The strategy recognises the importance of funding for energy infrastructure but does not provide detailed financial commitments or specific mechanisms beyond general sources. The focus is on mobilizing a mix of public, private, and international finance to support the transition to a low-emission energy system.
National Infrastructure Plan (NIP) 2050 (published 2022)	The NIP 2050 aims to drive South Africa's economic growth and transformation by developing sustainable and inclusive infrastructure across key sectors like energy, transport, water, and digital communications. It emphasises strengthening institutional capacity, fostering public-private partnerships, and enhancing regional integration to achieve the NDP vision of inclusive growth. Section 4 of the plan specifically outlines the financing elements required to deploy and maintain the infrastructure. The NIP 2050 outlines provisions for the funding of energy infrastructure in the following ways: • Government and public investment: The plan emphasises the role of government funding in strategic energy projects, including renewable energy initiatives, grid expansion, and modernization. This allocates resources for SOEs to improve energy generation and transmission capacity. • Private Sector and Public-Private Partnerships: Leveraging private sector investment through regulatory incentives, tax benefits, and co-financing models is emphasised. It also encourages independent power producers (IPPs) to participate in electricity generation, particularly in renewables.

Policy	Provisions in policy relating to the financing of energy infrastructure
	• International and Development Finance: This aims to secure funding from multilateral development banks, international climate finance mechanisms, and foreign direct investment (FDI). The plan also prioritizes grants and concessional loans for green energy projects. • Tariff Adjustments and Cost Recovery: Proposes reformation in energy pricing to ensure the financial sustainability of infrastructure. The plan also advocates for cost-reflective tariffs to reduce dependency on government subsidies.

Table 38: South African Laws and Regulations

Law/Regulation	Provisions in law relating to the financing of energy infrastructure
Electricity Regulation Act 4 of 2006	The latest amended version of the Electricity Regulation Act will accelerate South Africa's shift towards a decentralized, modern, and low-carbon energy system, enabling vital reforms that will accelerate the financing of the JET. This has the potential to unlock economic growth and job creation. The Act proposes a competitive multi-market structure for the South African electricity industry, encompassing 1) market transactions, 2) physical bilateral transactions, and 3) regulated transactions. • Transmission System Operator (TSO): The Act suggests establishing a TSO to manage the competitive multi-market. The TSO will handle transmission planning, operation, and control of the transmission system and market. It will also develop a transmission expansion plan aligned with the anticipated electricity demand, as outlined in the IRP. The TSO's role is crucial for the future of electricity supply and regulation. • Central Purchasing Agency (CPA): The Act also envisions creating a CPA within the TSO. This agency will buy legacy power purchase contracts and may acquire additional capacity and energy to maintain system integrity in a competitive environment. It will act as the 'Single Buyer', though the Act does not clearly define this term in the context of a competitive multi-market. Day-Ahead Market: The Act introduces the 'day-ahead market', which will match the supply of electrical energy with the expected demand for each hour of the trading day. This market is a welcome addition, as it promotes open electricity trade in South Africa. While the Act does not specify how the day-ahead market will be housed, set up, or operated, this is being developed by Eskom as part of the Market Code. The Act does not contain explicit funding provisions for energy infrastructure; however, the

	decentralization and liberalization of the market resulting from the Act will lead to greater policy and regulatory certainty, which will drive investor confidence.
National Energy Act 34 of 2008	The National Energy Act aims to ensure diverse energy resources are available in sustainable quantities and at affordable prices. It provides for the development of energy policies, integrated energy planning, and the establishment of institutions to promote energy R&D. The Act does not outline any specific financing provisions regarding energy infrastructure, however, Section 19 of the Act enables the Minister of Mineral Resources and Energy to create regulations regarding “measures and incentives designed to promote the production, consumption, investment, research and development of renewable energy”[40], “measures to ensure adequate provision of energy related Infrastructure"[41], and lastly measures to “promote security of supply through access to common infrastructure by any party, where not provided for under any other legislation”[42]. Although these provisions have never been used, the Act offers the opportunity for regulations to be introduced, specifically aimed at aiding the increased deployment of energy infrastructure. Some potential measures to introduce under these provisions are discussed in the international best practice section that follows. In addition, Section 18 specifically addresses “[i]investment and maintenance of energy infrastructure”.[43] This enables the Minister to direct any state-owned entity to undertake security of supply measures, provide for adequate investment in energy infrastructure, invest in critical energy infrastructure, and ensure upkeep of all critical energy infrastructure.
Public Finance Management Act (PFMA) 1 of 1999	The PFMA is a legislative framework that governs fiscal management in the public sector. While it does not directly address energy infrastructure, it plays a crucial role in shaping how public funds are allocated and managed. Section 38 requires accounting officers and authorities to establish a system for evaluating all major capital projects prior to a final decision on the project.[44] This means that when considering the procurement of energy infrastructure projects, any public sector department would have to evaluate such a project before making a final procurement decision. This

[40] See Section 19(1)(f) of the National Energy Act 34 of 2008.
[41] See Section 19(1)(o) of the National Energy Act 34 of 2008.
[42] See Section 19(1)(q) of the National Energy Act 34 of 2008.
[43] See Section 18(1)(b) and 18(1)(c) of the National Energy Act 34 of 2008.
[44] See Section 38(1)(a) of the Public Finance Management Act (PFMA) 1 of 1999 states that: “The accounting officer for a department, trading entity or constitutional institution (a) must ensure that that department, trading entity, or constitutional institution has and maintains; (i) effective, efficient, and transparent systems of financial and risk management and internal control; (ii) a system of internal audit under the control and direction of an audit committee complying with and operating in accordance with regulations and instructions prescribed in terms of Sections 76 and 77; (iii) an appropriate procurement and provisioning system which is fair, equitable, transparent, competitive and cost- effective; (iv) a system for properly evaluating all major capital projects prior to a final decision on the project.”

	process may delay the deployment of energy infrastructure projects by public sector entities such as Eskom and the NTCSA.
Pension Fund Act 24 of 1946	Regulation 28, issued in terms of Section 36(1)(bB) of the Pension Fund Act, protects retirement fund member savings by limiting the extent to which funds may invest in a particular asset or particular asset classes, and prevents excessive concentration risk. The regulations widen the scope of potential investments for retirement funds but continue to leave the final decision on any investment or investment policy to the trustees of each fund. The review of Regulation 28 is in response to several calls for increased investment in infrastructure, given the current low economic growth climate. The amendments seek to make it easier for retirement funds to invest in infrastructure. To this end, the amendments introduce a definition of infrastructure and set a limit of 45% for exposure in infrastructure investment. To facilitate further investment in infrastructure and economic development, the line between hedge funds and private equity has been blurred. There will now be a separate and higher allocation of 15% to private equity assets, increased from 10%. A limit of 25% has been imposed across all asset classes to limit the exposure of retirement funds to any one entity (company), not just infrastructure. However, one exception to the per-entity limit, is debt instruments issued by, and loans to, the Government of the Republic and any debt or loan guaranteed by the Government of the Republic.
Income Tax Act 58 of 1962	South Africa has introduced several energy incentives in its Income Tax Act: **Enhanced Renewable Energy Incentive for Businesses**: Proposed as Section 12BA in the ITA, this incentive enhances the existing renewable energy tax incentive (Section 12B). Its objective is to encourage investment in renewable energy sources to alleviate the energy crisis. Qualifying assets are new and unused equipment used for electricity generation from renewable sources (such as solar PV panels, wind turbines, and biomass facilities). This incentive is available for a two-year period, from March 2023 to February 2025. In 2023, the South African Government introduced a solar panel tax rebate to encourage individuals to invest in clean energy. This rebate allowed taxpayers to claim 25% of the cost of new and unused solar PV panels, up to a maximum of R15 000. The incentive was designed to increase electricity generation and support the clean energy transition. However, this incentive was available only for a limited period, from March 1, 2023, to February 29, 2024. However, this shows the Government’s commitment to introducing incentives which drive investment in energy infrastructure.

	Section 12L Energy Efficiency Savings Deduction: The Income Tax Act allows taxpayers to claim a deduction for energy-efficiency savings resulting from specific activities. The deduction is calculated at 95 cents per kWh or kWh equivalent. These incentives aim to promote sustainable energy practices and contribute to environmental goals.
Climate Change Act 22 of 2024	The Climate Change Act was signed into law on 23 July 2023 and took effect on 17 March 2025. The Act emphasises a structured approach to mitigating climate change through the establishment of carbon budgets, stringent monitoring, and compliance measures. It aims to enhance national resilience, contribute to global efforts, and ensure that socio-economic considerations are incorporated into climate action policies. Although the Act makes no provision related to the funding of energy, its provisions will most likely result in increased renewable energy investment by entities required to adhere to the climate change mitigation and adaptation measures outlined in the Act. More specifically, the following provisions will be relevant: National departments listed in Schedule 2 of the Act, which includes Energy, will be required develop and publish a Sector Adaptation Strategy and Plan within two years of the National Adaptation Strategy and Plan.[45] The Sector Adaptation Strategy must be informed by a climate change vulnerability assessment conducted for that sector and would need to outline measures and mechanisms to manage and implement the required adaptation response for the sector. Although the Sector Adaptation Strategy still requires further development, it is likely to require increased investment in renewables, as well as social development elements to help facilitate the transition away from coal, which is one of South Africa's main contributors to climate change. The Act would also require the Minister responsible for Energy (presumably the Minister of Electricity and Energy) to submit reports on the progress made in implementing the relevant Sector Adaptation Strategy and Plan.[46] Furthermore, the Minister responsible for Energy will also be required to implement sectoral emissions targets in terms of Section 25 of the Act. The sectoral target for energy would need to be in line with the national GHG inventory. Additionally, the sectoral emissions target would need to consider the socio-economic impacts of introducing sectoral emissions targets, as well as the best available scientific data and information. A sectoral emission target for the energy sector would likely lead to increased pressure to reduce emissions from fossil fuels, resulting in higher investment in renewables and lower-carbon sources of energy, such as gas.

[45] *Although the Act has been promulgated, it has yet to commence and will come into operation on a date to be proclaimed by the President in the Government Gazette.*
[46] *Please see Section 22(1) of the Act that sets out the requirements for the sector adaptation plans.*

7.2.3 Findings and Discussion of South African Analysis

There are policy and regulatory frameworks in place that govern the flow of public and private investments in energy infrastructure and service delivery with respect to technologies, service levels, and resilience in the face of climate change. However, based on this analysis, South African policies, such as the White Paper on Energy Policy and the White Paper on Renewable Energy, while foundational, lack the necessary updates and specificity regarding funding mechanisms. Although the Constitution does not explicitly mention renewable energy or a right to electricity, access to electricity is inferred from the right to adequate housing and other essential services. Sections 153 and 237 place the responsibility on municipalities to ensure sustainable service provision, including electricity.

The White Paper on Energy Policy of 1998 and its subsequent documents recognise the need for substantial investment and clear differentiation between funding for backlogged electrification and new infrastructure. Yet, without developed alternative funding and pricing mechanisms, the energy sector struggles with balancing cost-reflective tariffs and substantial tariff increases. The South African Renewable Energy Masterplan (SAREM) outlines ambitious strategies and funding recommendations, but these initiatives have not been implemented. The National IEP and the Draft IRP 2023 (DMRE, 2023b) also highlight funding needs but lack specific provisions for energy infrastructure financing, further exacerbating the gap in clear, actionable funding pathways for renewable energy and infrastructure development in South Africa. The Low Emissions Development Strategy 2020 acknowledges the need for energy infrastructure funding and outlines potential sources, including public-private partnerships, government funding, and international climate finance; however, it lacks detailed financial commitments or specific mechanisms. In contrast, the NIP 2050 offers a more structured approach, detailing funding strategies such as government investment, private sector participation, international finance, and cost-recovery mechanisms to support the expansion and sustainability of energy infrastructure.

The Electricity Regulation Act, while aimed at decentralizing and modernizing South Africa’s energy system, lacks explicit provisions for funding energy infrastructure. This omission creates a significant gap, as the decentralization and liberalization of the market alone do not ensure the necessary investment in energy infrastructure. Without clear funding mechanisms, achieving the Act’s objectives may be challenging despite the potential increase in investor confidence from regulatory certainty. The National Energy Act of 2008 does not specify financing provisions for energy infrastructure. However, it empowers the Minister of Electricity and Energy to introduce regulations that promote investment and ensure the provision of adequate infrastructure. However, these provisions have not been utilized, creating a gap in the direct funding mechanisms required for energy infrastructure deployment.

The policy and regulatory analysis also highlighted barriers that could hinder progress to achieving SDG 7.1 and NDP goals in South Africa. Inconsistent policies and regulatory frameworks have hindered progress. Delays in policy implementation and regulatory approvals slow down the deployment of new energy projects (RSA, 2021). Guiding policies, such as the White Paper on Energy Policy and the SAREM, promote the deployment of energy infrastructure and the increased use of renewable energy. Despite these policies outlining ambitious strategic objectives, the country’s legislation lacks the necessary provisions to formalize funding mechanisms. Although the country has now passed the Electricity Regulation Amendment Act, the success of the Act hinges on the Government’s willingness to carry out the reforms envisaged within the Act and the speed at which Government will publish the empowering rules and regulations to ensure better implementation of the Act. There is a need for a more coherent and supportive regulatory framework that encourages investment in renewable energy and energy-efficient technologies (NECOM, 2023). Regulatory complexities and uncertainty on future electricity prices further complicate the energy landscape (World Bank, 2021). Some local electricity distributors do not have the wheeling framework in place with the associated tariffs. This restricts the supply and use of renewable energy by private suppliers and customers within the municipal area of supply. This ultimately stifles the development of renewable energy projects designed to supply the customers within the municipal area of supply.

Section 7.3 below highlights international best practice mechanisms for South Africa to gain access to the necessary infrastructure funding.

7.3 International Best Practice Analysis

For this report, the international best practices of multiple countries were considered, including Germany, the United States (US), the United Kingdom (UK), and Malaysia (see Table 35 below). Lessons from other countries have also been considered where applicable. These countries were included as each employs unique best practices in energy funding mechanisms to advance their renewable energy goals. Germany's “Energiewende” (energy transition) programme is a leading example, using FiTs to guarantee long-term contracts and stable returns for renewable energy producers, thereby encouraging investment. The US leverages a mix of federal tax credits, such as the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), alongside state-level incentives and RPS that mandate a certain percentage of energy to come from renewable sources. Similarly, the UK’s Renewables Obligation mechanism requires electricity suppliers to source a specified proportion of their electricity from renewable sources, incentivized by tradable Renewables Obligation Certificates (ROCs) awarded to renewable energy generators. Collectively, these mechanisms reflect each country's tailored approach to fostering a sustainable energy transition while attracting private investment. Similar to South Africa, Malaysia is an upper-middle-income country. Both countries rely heavily on fossil fuels, particularly coal, for their electricity generation. In Malaysia, coal accounts for 43% of the power mix, while natural gas contributes around 47%. This is somewhat similar to South Africa, where coal accounts for a significant portion of the energy mix. Therefore, Malaysia will also be considered as a case study.

Table 39 outlines some of the mechanisms that have enabled the deployment of energy infrastructure in other countries. These mechanisms are discussed further in Sections 7.3.1–7.3.8 below.

Table 39 : International Best Practices in Energy Funding Mechanisms

Country	Energy infrastructure financing mechanisms to be considered
Germany:	Germany's Renewable Energy Sources Act (EEG) is a cornerstone of the country's transition to renewable energy, known as the "Energiewende". The EEG was first introduced in 2000 and has undergone several revisions to adapt to changing market conditions and technological advancements. The main objectives of the EEG include: 1) **Promoting the development of renewable energy sources** to reduce GHG emissions and combat climate change, 2) **Increasing energy security** by diversifying the energy supply, and 3) **Stimulating technological innovation** and economic growth in the renewable energy sector.
United States (US)	The US has implemented various regulatory measures to stimulate renewable energy deployment and investment. These measures include federal and state policies, tax incentives, and regulatory frameworks designed to promote renewable energy. Federal measures include the ITC and the PTC.
United Kingdom (UK)	The UK primarily uses CfD[47] This mechanism helps to stabilize prices and provides financial certainty, making it easier to attract private sector funding for renewable energy projects. By de-risking early-stage pilots and bridging the affordability gap, CfDs play a crucial role in developing innovative, low-cost, green financing solutions to support renewable energy. This is achieved by providing long-term price stability, which covers the difference between the market price and a pre-agreed strike price, thereby reducing the risk for investors. The Renewables Obligation mechanism mandates electricity suppliers to source a specific proportion of their electricity from renewable sources, with compliance facilitated through tradeable ROCs. Additionally, the UK offers the FiTs scheme, which guarantees payments to small-scale renewable energy producers based on the energy they generate and export to the grid, encouraging the adoption of decentralized renewable energy technologies.
Malaysia	Malaysia offers several tax incentives to promote renewable energy investments through the Green Technology Tax Incentive program. This includes the Green Investment Tax Allowance (GITA), which provides a 100% tax allowance on

[47] CfDs are financial agreements where the buyer and seller exchange the difference between the value of an asset at a specific future date and its value at the time the contract was initiated (meaning, if the current price is higher, the buyer gets paid the difference; if the current price is lower, the buyer pays the seller the difference).

Country	Energy infrastructure financing mechanisms to be considered
	qualifying Capex for green technology projects, and the Green Income Tax Exemption (GITE), offering a 70% tax exemption on statutory income for green technology services. Additionally, the Green Technology Financing Scheme (GTFS) supports projects with interest rate subsidies and government guarantees.

Based on the best practices in these countries, four possible mechanisms are recommended below to drive energy investment and funding in South Africa:

- Renewable energy funds,
- Renewable energy tax incentives,
- Renewable energy targeting mechanisms, and
- The introduction of pricing and return mechanisms.

7.3.1 Renewable Energy Funds

Several countries have introduced renewable energy funds to support the deployment of renewable energy projects. These funds are typically established through national legislation or policy initiatives. These funds are often part of broader national strategies to reduce GHG emissions, improve energy security, and stimulate economic growth through the development of renewable energy industries.

7.3.1.1 Germany

EEG Surcharge (EEG-Umlage)

The EEG surcharge (EEG-Umlage) is a key financial mechanism within Germany's EEG, designed to fund the promotion and integration of renewable energy into the electricity market.[48]

The EEG surcharge covers the difference between the guaranteed payments to renewable energy producers (under FiTs or market premiums mentioned above) and the revenue obtained from selling this renewable electricity on the market. This mechanism ensures that renewable energy producers receive stable and predictable revenue, encouraging investment in renewable projects. The revenue from the EEG surcharge has been instrumental in financing the expansion of renewable energy capacity in Germany, resulting in a substantial increase in the share of renewables in the German energy mix.

[48] *It is worth noting that the EEG surcharge is permanently abolished, and the federal government now provides funding directly. The new Energy Financing Act (EnFG) serves as the basis. It grants the transmission system operators (TSOs) a compensation claim against the federal government for payments made as financial support. This law will form the basis for surcharges such as those under the Combined Heat and Power Act. It therefore also includes the exemptions from the obligation to pay a surcharge. They continue to have high economic relevance for energy-intensive companies.*

Certain energy-intensive industries receive partial exemptions from the surcharge to maintain their international competitiveness. These exemptions reduce the financial burden on industries that consume substantial amounts of electricity and are exposed to global market pressures. Additionally, embedded self-generation solutions are also exempt from paying the surcharge as outlined in Section 62(a) of the EEG.

Calculation of the EEG surcharge: The surcharge is levied on electricity consumers through their electricity bills. It is paid for by virtually all electricity consumers, including households, businesses, and public institutions, although some large energy-intensive industries receive partial exemptions. The EEG surcharge adds to the electricity bills of consumers, typically constituting a sizeable portion of the total bill. While this increases electricity costs for consumers, it is designed to support the broader transition to renewable energy and reduce long-term environmental and health costs associated with fossil fuels.

Cost determination: The EEG surcharge is calculated annually by the TSOs. It is based on projected costs for the upcoming year, including estimated payments to renewable energy producers and anticipated revenue from selling renewable electricity on the market.

Market revenue offset: The total cost of renewable energy support is offset by the expected revenue from selling renewable electricity. This difference, which reflects the net cost, is what the EEG surcharge aims to cover.

Annual adjustment: The surcharge is adjusted each year to reflect changes in the cost of renewable energy production, the volume of renewable energy fed into the grid, market electricity prices, and the total electricity consumption in Germany. This ensures that the surcharge remains aligned with real-world costs and market conditions.

Challenges to be aware of from a South African perspective

- **Cost burden:** The rising costs associated with renewable energy support have led to increased EEG surcharges over the years, raising concerns about the affordability of electricity for consumers, particularly low-income households. If a similar mechanism was adopted in South Africa, it would be crucial to consider the social equity aspects of such a surcharge and ensure that the cost burden is distributed fairly, without disproportionately impacting vulnerable populations.
- **Exemptions debate:** The exemptions for energy-intensive industries are controversial, as they shift a greater share of the cost burden onto other consumers. These exemptions may undermine the principle of equitable cost distribution and reduce incentives for energy efficiency in exempted industries. Given the energy intensity of the South African economy, exemptions for large energy users are not recommended, as this will also encourage energy users to fund and deploy alternative energy solutions to avoid paying the surcharge.

- **Market integration:** As the share of renewable energy increases, its integration into the electricity market and the management of its variability become more challenging. The EEG surcharge needs to be complemented by investments in grid infrastructure, storage solutions, and demand-side management to ensure grid stability. Given the proposed transition to the wholesale electricity market in South Africa, integrating a similar provision within the new market context may be challenging.
- **Policy adjustments:** The EEG and its surcharge mechanism have undergone several revisions to address these challenges. Recent reforms aim to cap energy costs, enhance the market integration of renewable energy sources, and promote the cost-effective deployment of renewable energy technologies. In the South African context, policy adjustments are generally a lengthy process. However, incorporating the charge as part of the charges imposed by the Customs and Excise Act 91 of 1964 would remove lengthy policy adjustments and reduce the administrative burden. Mechanisms like the fuel or environmental levies can be considered and administered by the South African Revenue Service (SARS).

7.3.2 Renewable Energy Tax Incentives

US tax incentives serve as an example of international best practice. The ITC and the PTC are two key federal incentives designed to promote renewable energy development. These incentives are designed to encourage increased deployment of renewables and improve generation capacity at the plants.

7.3.2.1 Investment Tax Credit (ITC)

The ITC is a federal tax credit designed to support the installation of solar and other renewable energy systems. The credit is applied to the total cost of installing the system, allowing businesses and homeowners to deduct a portion of the installation costs from their federal taxes.

- **Key features**
  - **Percentage-based credit**: The ITC allows for a certain percentage of the installation costs of a renewable energy system to be deducted from federal taxes. Historically, this percentage has been set at 30% for solar installations, but may vary over time and is dependent on legislation.
  - **Eligible technologies**: While solar PV systems are the most common, the ITC also applies to other renewable energy technologies, including wind, geothermal, fuel cells, and certain combined heat and power (CHP) systems.
  - **Residential and commercial applications**: The ITC is available for both residential and commercial systems. Therefore, homeowners, as well as businesses, can take advantage of the tax credit.

    - **Step-down schedule**: The ITC has a step-down schedule, meaning the percentage of the tax credit decreases over time. For example, it may decrease from 30% to 26%, then to 22%, and potentially lower unless renewed or adjusted by new legislation.

- **Benefits**
    - **Cost reduction**: The ITC significantly reduces the upfront cost of renewable energy systems, making them more affordable for consumers and businesses.
    - **Market growth**: By lowering the cost barrier, the ITC has been instrumental in driving the growth of the renewable energy market in the US.
    - **Job creation**: The increased adoption of renewable energy systems, spurred by the ITC, has led to job creation in the manufacturing, installation, and maintenance sectors.

Box 3: Malaysia's Green Technology Tax Incentive programme

Malaysia has introduced several tax incentives to promote investments in renewable energy through the Green Technology Tax Incentive program. This program includes two main components: the Green Investment Tax Allowance (GITA) and the Green Income Tax Exemption (GITE).

GITA is designed to encourage businesses to invest in green technology projects. It offers:

- A 100% tax allowance on qualifying Capex incurred on green technology projects.
- An allowance that can be set off against 70% of the statutory income for each year of assessment.
- An incentive period that can be up to 10 years, depending on the type of project.

Green Income Tax Exemption (GITE)

GITE provides tax exemptions for income derived from green technology services and systems. Key features include:

- A 70% tax exemption on statutory income for qualifying green technology services.
- An exemption period of up to 10 years, depending on the scale and type of project.

7.3.2.2 *Production Tax Credit (PTC)*

The PTC is a federal tax credit designed to support the production of renewable energy. Unlike the ITC, which is based on the investment cost, the PTC is based on the actual energy produced by the renewable energy system.

- **Key Features**
  - **Per kWh credit**: The PTC provides a tax credit per kWh of electricity generated by the renewable energy system. The credit amount is specified by law and can be adjusted for inflation.
  - **Eligible technologies**: The PTC primarily applies to wind energy but also includes other technologies such as biomass, geothermal, and certain types of hydroelectric power.
  - **Duration of credit**: The PTC is available for a set duration, typically 10 years, from the date the facility starts to generate electricity.
  - **Phase-out schedule**: Similar to the ITC, the PTC has a phase-out schedule, which reduces the credit amount over time, unless renewed by Congress.
- **Benefits**
  - **Operational incentive**: By providing a credit based on the actual production of electricity, the PTC incentivizes the efficient operation of renewable energy systems.
  - **Revenue stream**: The PTC provides a steady revenue stream for renewable energy projects, enhancing their financial viability and attractiveness to investors.
  - **Long-term support**: The duration of the credit helps ensure the stability and long-term growth of renewable energy projects.
- **Comparison and Combined Benefits**
  - **ITC**: Focuses on reducing the upfront capital cost of renewable energy installations, facilitating projects getting off the ground.
  - **PTC**: Focuses on the long-term production and operational efficiency of renewable energy projects, providing ongoing financial incentives based on energy output.
  - **Combined impact:** Projects can sometimes benefit from both credits, although specific rules and limitations apply. The ITC helps with initial investment costs, while the PTC supports ongoing energy production, creating a comprehensive support Lessons for South Africa from the energy tax incentives in the US.

Both the ITC and PTC have played crucial roles in the growth of the renewable energy sector in the US, contributing to increased deployment of clean energy technologies, reduced GHG emissions, and the transition towards a more sustainable energy future.

Similar incentives can be introduced in terms of the Income Tax Act 58 of 1962 and supported by a set of regulations introduced under Section 19 of the National Energy Act. Similar mechanisms would enable the deployment of renewables but also encourage electricity generation from renewable energy resources. Specifically, a tax incentive focused on the generation elements would be beneficial, as the Income Tax Act already contains investment incentives as outlined above. The tax credit could be similar to the PTC in the US, i.e., the credit could be claimed per kWh of electricity generated by the renewable energy system. Such an incentive is particularly useful given that financiers are hesitant to invest in renewables, due to the current low rate of returns.

7.3.3 Renewable Energy Targeting Mechanisms

Although not a specific financial mechanism, countries worldwide have adopted mechanisms that mandate distributors to procure a certain amount of their distribution capacity from renewable energy generators. Renewable energy targeting mechanisms play a pivotal role in accelerating the deployment of renewable energy by providing policy certainty, stimulating investment, fostering technological innovation, creating jobs, and achieving environmental objectives.

Some examples of renewable energy targeting mechanisms that have successfully aided the funding and deployment of renewable energy are outlined in Table 40:

Table 40: Renewable Energy Targeting Mechanisms Adopted in the US, Denmark, and UK

Country	Renewable energy targeting mechanism adopted
United States (US)	RPS are state-level policies that mandate that utilities generate or purchase a specified percentage of their electricity from renewable energy sources. These standards are a key regulatory mechanism aimed at promoting the deployment of renewable energy technologies and reducing GHG emissions from the electricity sector. RPS policies are primarily implemented at the state level in the US, rather than being federally mandated. Each state sets its own targets, timelines, and compliance rules based on its renewable energy potential, policy goals, and economic considerations. This is a unique feature for South Africa to consider, as our municipal distributors are at various levels of preparedness regarding energy procurement. Should a similar mechanism be considered for South Africa, each municipality must be given a level of discretion to develop its own targets and timelines. Utilities in the US must demonstrate compliance with RPS targets by either generating renewable energy themselves, purchasing renewable energy credits from renewable energy producers, or entering PPAs with renewable energy developers.
Denmark	Denmark sets annual renewable energy targets, and energy suppliers must demonstrate compliance with these targets by purchasing enough green certificates equivalent to a

	specified percentage of their total electricity sales. This mechanism ensures that the demand for green certificates drives investment in renewable energy projects. Green certificates are tradable commodities on the market. Energy suppliers and other obligated parties, such as large consumers or utilities, purchase these certificates to meet their renewable energy obligations and demonstrate their commitment to sustainability. Overall, Denmark's green certificate system has been instrumental in expanding renewable energy capacity and enhancing the sustainability of the country's energy sector, serving as a model for other countries looking to promote renewable energy through market-based mechanisms.
United Kingdom (UK)	The Renewables Obligation scheme in the UK is a policy mechanism designed to support the development and deployment of renewable energy sources. The Renewables Obligation operates by placing an obligation on electricity suppliers to source a certain proportion of their electricity from renewable sources. For each MWh of eligible renewable electricity generated, a renewable energy generator receives an ROC. Each year, the government sets an obligation level, which is the number of ROCs suppliers must present to demonstrate compliance. This is expressed as the number of ROCs per megawatt-hour of electricity supplied to customers. Electricity suppliers must meet their obligations by presenting the required number of ROCs. If the suppliers fail to surrender the required number of credits, they pay a buy-out price for any shortfall in ROCs. The money goes to a buy-out fund, and the funds are redistributed to suppliers, in proportion to the number of ROCs they have presented. This creates an additional financial incentive for suppliers to source renewable energy and present ROCs.

Lessons for South Africa to consider renewable energy targeting mechanisms

In South Africa, the concept of trading with renewable energy certificates (RECs) has been introduced, but has yet to develop as fully as the models outlined above. The system currently in place in South Africa is voluntary and not outlined in any regulatory instrument. In the South African system, renewable energy generators voluntarily participate in the system and are issued with RECs should they meet the necessary criteria. The voluntary nature of the system in South Africa has also enabled companies to purchase and retire RECs, thereby reducing their reported Scope 2 emissions.

A new renewable energy targeting mechanism can be introduced, like the international best practice mechanisms outlined above. Municipalities can be required to procure a certain percentage of their electricity from renewable energy projects. In such a scenario, the system would need to be similar to international examples where municipalities in South Africa would need to provide RECs to the regulator (NERSA) to substantiate their renewable energy procurement. Such a mechanism could either be launched by introducing a new law focused on the deployment of renewable energy, similar to the

Renewable Energy Act in Germany, or by publishing a set of regulations under Section 19 of the National Energy Act, specifically aimed at promoting and funding the deployment of renewables.

7.3.4 Introduction of Pricing and Return Mechanisms

Market sounding participants indicated that pricing is a significant barrier when determining the funding available for investment in energy infrastructure within the South African market. There is a need for pricing to be rebalanced and, thus, more attractive to investors to stimulate the required funding for energy generation, distribution, and transmission infrastructure. Some pricing stability and revenue mechanisms are set out below:

Capacity Markets

In some jurisdictions, capacity markets have been introduced that typically deliver higher revenues. In addition to the energy market where electricity is bought and sold, some regions have capacity markets. These markets pay power plants not just for the electricity they generate, but also for their availability to generate when needed. This provides a steady revenue stream for investors.

Capacity Market in the United Kingdom (UK)

The Capacity Market is part of the UK Government's electricity market reform package. It ensures security of electricity supply by providing additional payment for reliable capacity sources, in addition to their electricity revenues, to ensure they deliver energy when needed. This encourages the investment required to replace older power stations and provide backup for more intermittent and inflexible low-carbon generation sources.

The market functions by means of auctions as follows:

- **The T-4 Auction** is held four years ahead of the delivery year. This auction secures most of the required capacity.
- **The T-1 Auction** is held one year ahead of the delivery year. This auction is used to fine-tune the capacity requirements based on more accurate demand forecasts.
- Note that additional auctions can be held if necessary.

Successful bidders enter into Capacity Agreements, which commit them to being available to provide capacity or reduce demand when called upon during the delivery year. In addition to providing a stable revenue stream for investors, capacity markets also help maintain a balanced and stable electricity market by incentivizing the right mix of capacity. This increases investor confidence by mitigating some of the physical risks associated with grid stability.

South Africa is currently developing its capacity services market as part of the wholesale market structure, which will be introduced under the Electricity Regulation Amendment Act. One of the market platforms to be introduced includes capacity remuneration schemes whereby contracts can be entered into to provide capacity for longer-term supply security. The key component of the capacity payment will be an availability rate. If the generator is unable to meet its declared supply availability rate, an availability penalty is applied.

Ancillary Services Markets

These markets pay providers for services that help to maintain grid stability, such as frequency regulation, voltage support, and reserve power. These additional revenue streams can make investments in certain types of power plants more attractive. During the delivery year, participants must meet their obligations by being available to generate electricity to stabilize the grid, mitigating system stress events. Failure to deliver results in penalties, ensuring that participants are incentivized to perform as required.

Ancillary Services Market in the UK

The UK ancillary services market operates under the oversight and management of the National Grid Electricity System Operator (ESO). The ancillary services market has two main elements:

- **Frequency response**: These are ancillary services that help maintain grid frequency within the required range (50 Hz). This includes fast-acting services like Fast Frequency Response and Firm Frequency Response.
- **Reserve services**: These are standby capacities that can be rapidly activated to balance sudden changes in electricity supply or demand. This includes both operating reserves (used to respond within seconds to minutes) and contingency reserves (used for longer-term responses up to several hours).

The ancillary services market operates through competitive tenders and contracts. Providers of ancillary services, such as generators, battery storage operators, demand response providers, and other flexible resources, participate by bidding in auctions or submitting offers to supply specific types and amounts of ancillary services. The National Grid ESO evaluates these bids and offers based on technical and economic criteria to ensure the reliability and cost-effectiveness of procuring ancillary services. This competitive process helps to maintain grid stability by efficiently managing fluctuations in electricity supply and demand, ensuring the continued reliability of the electricity grid across the United Kingdom.

Lessons for South Africa to consider based on other pricing and return mechanisms

In South Africa, the power required to balance the system in real time will be procured through ancillary services and day-ahead reserve markets. The planned ancillary services market for South Africa will enable generators to declare that they are available at specified times to produce a certain amount of power if there is a shortfall. The generators will be compensated for making themselves available on standby and for any electricity produced during this timeframe. Due to the higher dispatchability and system coordination requirement for this type of generation, the price of electricity on this market is envisioned to be higher, making it an attractive proposition for funders. Although the proposed ancillary services market aligns with the ancillary services markets adopted abroad, a successful ancillary services market in South Africa would require:

- **Market design** to ensure transparency, fairness, and competitiveness. This includes defining market rules, pricing mechanisms, and settlement procedures.
- **Implementing incentives** for providing ancillary services to ensure reliability and quality.
- **Implementing penalties** for non-compliance to ensure reliability and quality.
- **Investing in grid modernization** to handle the integration of ancillary services effectively. This includes advanced metering, communication systems, and control technologies.

The market-wide capacity mechanism for South Africa has not yet been decided, but will be based on a Capacity Remuneration Mechanism. Capacity payments can be made to both consumers who reduce their demand and generators who increase their supply of electricity. These payments are categorized according to several factors, including the type of capacity being made available, the duration of the obligations, and how the payment costs are determined and allocated.

Although the capacity and ancillary markets are being developed under the Market Code, the mechanisms applied in other countries must be analysed with due consideration of unique South African circumstances.

7.3.5 Deemed Energy Payments

Network risk is one of the main challenges that IPPs face when concluding bilateral PPAs with private off-takers, especially when the generation and off-taker facilities are not co-located. In mature, liberalized electricity markets, the Network Service Provider (NSP) guarantees a minimum level of network availability, which is crucial for enabling wheeling transactions. This principle is outlined in the Regulatory Rules on Network Charges for Third-Party Transportation of Energy published by NERSA[49].

Morocco is one example of an African jurisdiction that has adopted a mechanism to address network risk. Morocco's power sector reforms have been unique, driven by strong political objectives for rural electrification and decarbonization. The country has achieved nearly 100% rural electrification and is a leader in implementing renewable energy strategies. Over half of Morocco's electricity comes from private generation plants, with significant private participation in distribution. Despite reforms, Morocco

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[49] *See references to the availability of the network in the Regulatory Rules on Network Charges for Third-Party Wheeling of Energy. The Rules specifically mention use-of-system (UoS) charges which are charges meant to recover the costs associated with the use of, and making capacity available on, an electricity network. These charges are the unbundled regulated tariffs, charged by the Transmission or Distribution Licensee as a network service provider for making transmission or distribution capacity available to generators and loads.*

has maintained a strong, state-owned, and vertically integrated national power utility, the *Office National de l'Electricité et de l'Eau potable* (ONEE). Reforms were pursued selectively and incrementally, even in the presence of legacy entities similar to Eskom in South Africa. For example, policymakers were selective in privatizing electricity distribution through concessions, involving eleven distribution companies, including seven public municipal utilities and four private concessions. These contracts typically cover the management and maintenance of electricity, water, and sewerage assets, minimizing revenue loss impacts on municipalities and enabling cross-subsidization.

Under Morocco's Renewable Energy Law 13-09, IPPs can sell power directly to industrial clients connected to high and medium voltage networks. The law also allows IPPs to use the national grid for electricity transport under a Grid Access Agreement with ONEE. This agreement ensures access to the National Electricity Network and the wheeling of produced electricity from production sites to consumption delivery points. In cases of 'energy not delivered' or "Energie Non Livrée" (ENL) due to network unavailability, ONEE will deliver electricity directly to the final consumer on behalf of the IPP or compensate the IPP according to the agreement terms.

ONEE has set a 2% threshold of monthly production for line maintenance, with no penalties within this threshold. Exceeding this threshold requires the generator to estimate ENL monthly based on the energy that should have been produced during disconnection or grid constraint periods. Compensation for unsupplied energy is calculated for each hourly period (peak and off-peak) and added to the month's production if uncontested by either party.

The principles defined in NERSA's Regulatory Rules should be enforced and should be legally binding for Eskom or any other NSP. This will mitigate one of the major project risks and streamline negotiations with bilateral PPAs, as wheeling enables sustainable investment for all parties. A good example of such enforcement is the Moroccan TSO (ONEE) and the SPV signing the Grid Access Agreement, which regulates the ENL mechanism. A similar provision or mechanism should be considered for South Africa to provide generators with greater security in the event of forced curtailment by Eskom.

7.3.6 Allowing Payments to IPPs Generating Energy During the Plant Testing Phase

Renewable Energy Technical Evaluation Committee (RETEC) approval from Eskom is a crucial step for renewable energy projects in South Africa, ensuring they meet the necessary grid connection and compliance standards set by Eskom. During the testing phase prior to obtaining RETEC approval, renewable energy generators typically do not receive payment for the electricity produced. This phase is often used to test and verify the performance of the plant's systems and equipment.

After RETEC grants approval, Eskom/NTCSA does not credit the early operating energy generated during testing and while waiting for approval from Eskom/NTCSA post-report submission. This could amount to tens of millions of kWhs that Eskom can sell, thereby benefiting Eskom/NTCSA and incentivizing RETEC to delay approvals. Additionally, this discourages the IPP from generating early energy due to the operational costs that cannot be recovered without the sale of this early energy.

There are international examples from other jurisdictions where renewable energy generators receive payment for the testing phase of the project. In Australia, renewable energy generators can receive compensation during the testing phase under specific conditions.

In Australia, the National Electricity Market (NEM) provides a framework that allows electricity generators to be remunerated for electricity generated during the testing and commissioning phase. This process is regulated by the Australian Energy Market Operator (AEMO) and governed by rules set out by the National Electricity Rules (NER). The NEM operates on a spot market, where electricity prices are set every five minutes based on supply and demand. The National Electricity Rules are the regulatory framework governing the NEM. They outline the procedures and conditions under which new generators can connect to the grid and participate in the electricity market, including the testing and commissioning phases (Australian Energy Market Commission (AEMC), 2024).

Clause 5.7A specifies the commissioning process for new generators, including the testing period. Generators must notify AEMO and the relevant NSP about the testing activities. Under this clause, once a generator has been connected to the grid, it can operate in test mode, allowing it to generate and sell electricity to the market.

Clause 3.8.3 relates to market participation and dispatch. This clause allows generators to bid into the NEM spot market, even during testing. Provided they meet all technical requirements and have registered with AEMO, they can sell electricity at prevailing market prices during commissioning.

Given the promulgation of the Electricity Regulation Amendment Act and the impending development of the wholesale market, the Market Code/Rules supporting the functioning of the market must include similar provisions to create greater investor confidence based on the remuneration of electricity generated during the connection phase.

7.3.7 Introduce Grid Connection Guarantees

On 6 May 2024, Eskom applied to NERSA in terms of Section 21(2) of the Electricity Regulation Act, seeking NERSA's approval to reserve and preserve grid connection capacity in favour of any project procured in terms of a ministerial determination published under Section 34 of the Electricity Regulation Act (NERSA, 2024)[50]. NERSA rejected Eskom's application based on Eskom's failure to justify

[50] *National Energy Regulator of South Africa (NERSA), Grid Capacity and/or preservation for Section 34 Determination Independent Power Producers, available at https://www-nersa-org-za.b-cdn.net/wp-content/uploads/bsk-pdf-manager/2025/01/Reason-for-Decision-on-Grid-Resevation-or-preservation-for-s34-IPPs.pdf*

discriminating between public and private energy projects regarding grid access. Eskom's application aimed to support the REIPP Bid Window 7 process, but NERSA found that the application lacked specific details regarding which customers would be affected. This decision maintains the current 'first come, first served' principle for grid capacity allocation (NERSA, 2024).

To avoid similar applications and expedite the grid connection process, it is recommended that REIPPP projects secure grid connections with guarantees as a prerequisite for bidding. This approach may reduce the bottleneck caused by delays in the government procurement process by ensuring that only projects with confirmed grid access are processed. It would also increase certainty in project timelines, avoid locking up grid capacity, and allow for faster development of bilateral projects.

Lessons for South Africa Based on Germany's Grid Connection Guarantee Mechanism

In Germany, IPPs are required to obtain grid connection guarantees from the relevant transmission system operator (TSO) before they can participate in the country's renewable energy auctions. This ensures that projects have a clear path to grid integration. The requirement is set out in the Renewable Energy Sources Act, known in German as Erneuerbare-Energien-Gesetz (EEG). Securing grid connection guarantees before bidding minimizes the risk of over-allocating grid capacity. This would reduce the likelihood of conflicts between REIPPP and bilateral projects. The German model has helped streamline grid integration and renewable energy development by reducing delays caused by grid connection issues post-auction. Applying this to the REIPPP would help avoid multi-year delays that have plagued some rounds of procurement. To implement this, Eskom (or other transmission operators) would need to develop a transparent process for issuing grid connection guarantees, similar to that of TSOs in Germany.

7.3.8 Discussion on International Best Practice Analysis

The review of international regulatory frameworks highlights several mechanisms that have successfully driven investment in energy infrastructure across various jurisdictions. A key factor observed is the presence of stable and transparent regulatory environments that provide long-term certainty for investors. Countries with clear legal and policy frameworks, including well-defined tariff structures and predictable regulatory processes, have been more effective in attracting private sector participation. Additionally, incentive-based regulation, such as performance-based ratemaking and return-on-equity guarantees, has played a crucial role in promoting investment by ensuring a fair and predictable return for investors.

The analysis also identifies the importance of competitive procurement mechanisms, particularly for renewable energy projects. Jurisdictions that have implemented auctions and tendering processes for energy infrastructure development have experienced lower costs and increased investor confidence, largely due to transparent bidding procedures. Furthermore, streamlined permitting and approval processes have expedited project development, reduced bureaucratic delays, and minimized regulatory uncertainty.

Another successful approach is the use of hybrid financing models that leverage public-private partnerships. These models have enabled risk-sharing between governments and private investors, fostering greater capital inflows into energy infrastructure. Additionally, regulatory mechanisms that support grid modernization and integration of new technologies, such as smart grids and energy storage, have further facilitated investment by ensuring adaptability to evolving energy needs.

Overall, jurisdictions with proactive regulatory bodies that engage in continuous dialogue with industry stakeholders and adjust frameworks to evolving market conditions have been more successful in maintaining robust investment in energy infrastructure. These findings illustrate the crucial role of regulatory certainty, incentive structures, competitive mechanisms, and efficient permitting processes in fostering a climate conducive to investment.

7.4 Conclusions

The regulatory landscape in South Africa reflects a fragmented and underdeveloped framework that poses significant challenges for financing and attracting sustained investment in energy infrastructure. Despite having ambitious goals for energy transition and infrastructure development, South Africa continues to lack the integrated and coherent legal architecture required to catalyse private and public sector investment at scale.

A key barrier is the absence of a unified legislative framework that prioritizes energy infrastructure as a national strategic investment area. Currently, regulatory responsibility is dispersed across multiple departments and agencies, which creates procedural uncertainty, prolonged licensing processes, and limited coordination. This regulatory fragmentation deters investors seeking stable, predictable, and transparent policy environments. Moreover, the lack of enforceable timelines and accountability mechanisms in infrastructure procurement and development processes hinder investor confidence and long-term project planning.

Another critical gap lies in South Africa’s inability to effectively de-risk energy projects through legislative and institutional support. Countries with more mature investment environments have codified mechanisms such as government-backed guarantees, blended finance facilities, and sovereign support instruments. These features are largely missing or inconsistently applied in South Africa. Furthermore, the current procurement frameworks, such as REIPPPP, while successful in some respects, lack overarching legislation to entrench their continuation or expansion. This regulatory fragility undermines efforts to attract consistent, large-scale investment in energy infrastructure.

By contrast, the international best practice analysis underscores how countries that have successfully mobilized investment in energy infrastructure have done so by adopting robust and streamlined legal and regulatory frameworks. For example, countries like Chile and India have enacted specific legislation to enable IPPs, clearly delineate the roles of regulators, and provide regulatory certainty through long-term policy instruments. These frameworks are not only investor-friendly but also agile enough to respond to evolving technological and market conditions.

The international examples also reveal the strategic role of integrated planning laws and policy coherence. Many national governments have adopted long-term infrastructure planning legislation that is often supported by independent institutions or agencies tasked with identifying infrastructure priorities, coordinating stakeholders, and facilitating investment. This has enabled more effective project identification, faster approvals, and reduced policy risks for investors. These governments have further incentivized investment through targeted fiscal instruments, including tax incentives, green bonds, and concessional financing aligned with climate and development goals.

Ultimately, a comparison to these case studies highlights that while South Africa has expressed a strong political commitment to energy infrastructure development, this has not yet been translated into a robust regulatory system capable of delivering investment at the required pace or scale. Without targeted reforms to address institutional fragmentation, streamline approval processes, and establish a comprehensive legal framework for infrastructure financing, South Africa risks falling behind global peers in securing the investment necessary to meet its energy and climate objectives.

The international responses in the form of regulatory reformations is also a form of disruptive innovation, which would aid the achievement of SDG 7.2 (by 2030, increase substantially the share of renewable energy in the global energy mix) and SDG 7.3 (doubling the global rate of improvement in energy efficiency compared to the 1990–2010 baseline). Regulatory frameworks play a crucial role in fostering the rapid development and integration of new technologies. Eliminating regulatory obstacles and fostering the development of new technologies is crucial to accelerate the transition to a climate-friendly future, resulting in cost reductions and increased investment attraction. South Africa's climate policies, such as the NDP and IRP, have already introduced energy efficiency measures and set ambitious goals for reducing GHG emissions. Regulatory adjustments can facilitate system-level disruption in the energy sector, influencing technological expertise and established practices, thereby advancing SDG 7.2 and 7.3 (SARB, 2022).

7.5 Recommendations

This analysis established that South Africa has core guiding policies, such as the White Paper on Energy Policy and the SAREM, which aim to promote the deployment of energy infrastructure and the increased utilization of renewable energy. Although these policies outline ambitious strategic objectives, the country's legislation lacks the necessary provisions to formalize funding mechanisms. Based on international best practices, South Africa should consider policy, institutional, and regulatory reforms to increase investment in climate-resilient energy infrastructure and services, thereby achieving the targets set by the SDGs and supported by the NDP (Chapter 5).

- **Renewable energy fund**: Introduce a renewable energy surcharge, modelled on Germany's EEG, to fund clean energy projects while ensuring fairness for low-income households and equitable cost-sharing across all users. Complement this with grid upgrades, storage investments, and demand-side management to stabilize the grid and streamline the surcharge by integrating it into existing tax systems.
- **Tax incentives**: Offer tax breaks, such as the ITC and PTC in the US, to lower upfront costs and reward energy production, thereby driving renewable energy investment and sustained growth. South Africa has introduced tax incentives for households and businesses, as discussed in the analysis of the Income Tax Act 58 of 1962. Incentives aimed at utility-scale deployment, such as those in the US, would be required to drive large-scale investment.
- **Targeting mechanisms**: Mandate municipalities to source a set percentage of electricity from renewables, with flexible targets and timelines. Use RECs to ensure compliance and incentivize investments through supportive legislation.
- **Pricing and returns**: Create capacity and ancillary services markets to secure a reliable power supply and grid stability, with fair, transparent incentives for availability, generation, and stability services.
- **Deemed energy payments**: Protect IPPs against network risks by enforcing NERSA rules and adopting models like Morocco's Grid Access Agreements, ensuring compensation for undelivered energy due to grid issues.

- **Move the Grid Access Unit (GAU) from Eskom Distribution to the NTCSA or another independent entity:** The GAU is currently part of Eskom Distribution, the same entity responsible for collecting revenue from Eskom customers. IPPs connecting to the network outside of the REIPPP are competing with Eskom Distribution for these customers, aligning with the Electricity Regulation Act principle of creating an energy market in line with international trends. This situation creates a conflict of interest for the GAU because every connection it approves for wheeling projects not related to the REIPPP programme reduces the revenue prospects for the entity it reports to. This structure is unsustainable and creates perverse incentives, hindering the efficient delivery of connections and projects based on bilateral PPAs.

Additionally, the GAU often needs to collaborate with the NTCSA for connection designs and modelling, requiring resources from entities over which it has no authority. This lack of authority results in significant delays in the progression of technical designs and user requirements for prevailing grid connections.

Making the GAU an independent entity or consolidating it with the NTCSA could offer several benefits:

- **Reduced conflict of interest:** By separating the GAU from Eskom Distribution, the potential conflict of interest is minimized. This ensures that decisions regarding grid connections are made more objectively, without the influence of revenue considerations from Eskom Distribution.
- **Improved efficiency:** An independent entity focused solely on transmission can streamline processes and reduce delays in connection designs and modelling. This can lead to faster and more efficient project approvals and implementations. Specialized attention to grid access issues could potentially lead to more innovative and effective solutions for expanding grid management.
- **Enhanced collaboration:** The GAU would have direct access to resources and authority within the new structure, facilitating better coordination and collaboration. This can improve the progression of technical designs and user requirements for grid connections.

However, for the GAU to become an independent entity or consolidated with the NTCSA, certain regulatory reforms might be required. The GAU mandate includes facilitating and managing the grid access entry of IPPs and other generators, providing holistic solutions to serve their needs appropriately, ultimately resulting in successful and viable grid connections and operations.

The mandate of the NTCSA, as set out in Section 34B of the Electricity Regulation Amendment Act, includes that the transmitter is responsible for providing non-discriminatory access to the transmission power system to third parties. The facilitation and management of grid access by the GAU is fundamentally different from and does not equate to the basic provision of grid access, which is the responsibility of the NTCSA. Facilitation and management are administrative functions that involve guiding and supporting IPPs through the process of connecting to the grid. In contrast, the provision of access is an oversight function that involves granting the actual physical and regulatory access to the grid. In summary, while both the GAU and NTCSA play crucial roles in the grid access process, their functions are distinct. The GAU’s administrative role in facilitating and managing grid access is different from the NTCSA’s oversight role in providing access. Any structural changes would require careful consideration and legislative amendments to ensure clarity and efficiency in their respective mandates.

Section C: Summary of Key Findings, Conclusions, and Recommendations

8 Summary of Key Findings

Operating Capacity

CAPACITY EXPANSION	REGULATORY & MARKET REFORMS	POLICY & REGULATORY REFORMS
• Scenario A/B/C: align investment with cliamte and cost outcomes	• Reprice debt instruments to ensure liquidity	• Create a renewable energy fund via fair surcharges
• Expand VRE: 7 GW per year to 2030, then 5 GW per year	• Improve clarity & consistency in renewable programmes	• Offer tax incentives for renewable investment
• Incoporate gas & battery storage to support VRE	• Provide Treasury-backed guarantees and develop a wholesale market	• Set municipal renewable procurement targets
• No new coal or nuclear plants; maintain existing fleet	• Improve Eskom efficiency & implement transmission programme	• Establish capacity & ancillary service markets
• Promote decentralized microgrids & co-location of generation	• Encourage private-sector participation & innovative funding	• Adopt deemed-energy payments and relocate GAU
• Monitor disruptive technologies (e.g. CCS, innovation)		

The technical modelling identified the energy mix with the lowest investment requirement to meet national electricity demand, based on various input assumptions and model constraints for each scenario. The operational capacity for each generation and storage technology required by 2030 and 2050 for each scenario is shown in Table 1.

Scenario A results in the largest and most accelerated roll-out of solar PV and wind, supported by BESS and gas at a low-capacity factor. It also results in the fastest decommissioning of the coal fleet. Scenarios B and C result in progressively less solar PV, wind, and BESS capacity, with more coal remaining online for longer. Gas capacity also features at a relatively low-capacity factor in scenarios B and C, compared to Scenario A, which indicates a peak of operation.

Given the urgent need to address energy shortages over the short- to medium-term (2025–2035), no new coal or nuclear capacity is envisaged during this period. Furthermore, the modelling reveals that across all three scenarios, the system can meet reliability and emissions constraints through a mix of renewables, storage, and flexible gas capacity without requiring new coal or nuclear investments through to 2050.

From 2030 onwards, all scenarios entirely meet the demand, i.e., there is no unserved energy or load shedding observed beyond 2030.

Table 41: Operating Capacity per Technology in 2030 and 2050 per Scenario (GW units)

Year	Technology	Scenario A (Green Industrialization)	Scenario B (Market Forces)	Scenario C (Business-as-usual)
2030	Solar	31	21	23
	Wind	18	11	10
	BESS	11	2	2
	Gas	9	7	5
	Coal	14	34	34
	Hydro	4	4	2
	Nuclear	2	2	2
2050	Solar	99	64	52
	Wind	48	33	32
	BESS	53	33	25
	Gas	23	26	29
	Coal	10 (CCS)	10 (CCS)	11
	Hydro	5	5	5
	Nuclear	2	2	2

Note: Operating capacity refers to total system capacity available in each year, calculated as existing capacity minus decommissioned capacity plus any new capacity added. This includes both legacy and new-build plants that remain online in the model year.

Grid Expansion

In all scenarios, the highest power flow is from Free State to Gauteng and Northern Cape to Gauteng via North West, followed by the flow from Hydra Central to Free State. In scenarios A and B, significant renewable energy capacity is built, with a larger portion located in the Northern Cape and Hydra Central due to the favourable VRE resource. Subsequently, transmission corridors are required to transport this VRE power to the load centre in Gauteng, hence the biggest transmission corridors are the Northern Cape to Gauteng via North West, and Hydra Central to Gauteng via the Free State corridors. In addition, power from the Eastern Cape is transported to Gauteng via the Free State to Gauteng / Mpumalanga corridor. Similarly, power from Limpopo is transported to Gauteng via the North West to Gauteng corridor.

The required transmission backbones, collection lines, and substations, as well as distribution collector networks (for VRE and BESS capacity), were quantified based on the geographic location of new capacity and the required corridor flows. The investment required for new distribution collector networks is substantial compared to the total grid expansion investment, representing 53%, 47%, and 43% of total grid expansion investment for scenarios A, B, and C, respectively.

CO_2 Emissions

Scenarios A and B both had CO_2 emissions constraints applied. The constraint in Scenario A was based on meeting or exceeding the current NDC targets, while the constraint in Scenario B would likely partially exceed the current NDC targets. Scenario C was unconstrained from a CO_2 emissions perspective. None of the scenarios were constrained to achieve zero CO_2 emissions by 2050.

The resultant CO_2 emissions per scenario from 2023 up to 2050 are shown in Figure 56. Scenario A achieves 123 Mt/a CO_2 emissions in 2030, which is within the current NDC range for the power sector. Scenarios B and C achieve 181 Mt/a CO_2 emissions in 2030, which is on the extreme upper end or exceeds the NDC contribution for the power sector, depending on the source. Scenario A results in the lowest CO_2 emissions by 2050 (8 Mt/a).

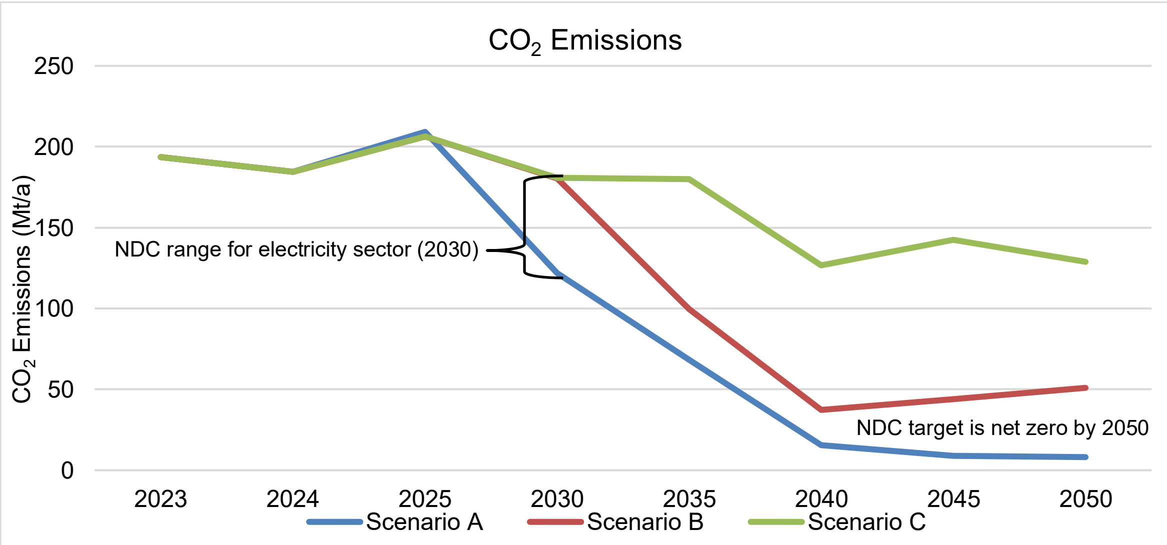

Figure 56: CO_2 Emissions per Scenario

Investment Required

The total investment required per scenario from 2025 to 2050 is shown in Table 42. Scenario A requires the largest build of new power generation and storage capacity, yet it results in the lowest total system investment due to more optimistic technology learning rates and lower variable generation costs, resulting from lower fuel requirements and lower fuel prices. Scenario C, although requiring the smallest build of new power generation and storage capacity, results in the highest total system investment due to the least optimistic technology learning rates and higher variable generation costs.

Table 42: Total System Investment per Scenario from 2025 to 2050 (R'bn, discounted 8% to 2024 real terms)

Investment detail	Scenario A (Green Industrialization)	Scenario B (Market Forces)	Scenario C (Business-as-usual)
Total Generation Investment	3 203	3 395	3 935
Total Grid Investment	383	262	231
Total System Investment	3 586	3 657	4 166

The average annual investments per period per scenario are shown in Table 43 below. Scenario A requires the highest average annual investment from 2025 to 2030, due to the accelerated scale of new VRE and BESS capacity roll-out during this timeframe, compared to scenarios B and C. Scenario A benefits from the lower variable generation costs, and requires the lowest average annual investment from 2031 to 2050, compared to scenarios B and C.

Table 43: Average Annual Investment per Period per Scenario (R'bn, discounted 8% to 2024 real terms)

Scenarios		Scenario A (Green Industrialization)		Scenario B (Market Forces)		Scenario C (Business-as-usual)	
Investment detail		**2025–2030**	**2031–2050**	**2025–2030**	**2031–2050**	**2025–2030**	**2031–2050**
Capex	**Generation**	125.3	44.9	59.1	43.7	80.6	48.1
	Grid	14.7	14.7	10.1	10.1	8.9	8.9
	Total	140.1	59.7	69.2	53.8	89.4	57.0
	% of GDP	1.9%	0.8%	0.9%	0.7%	1.2%	0.8%
Opex	**Variable cost**	70.4	15.2	89.1	49.3	112.7	56.9
	Fixed costs	54.1	25.0	49.8	17.3	50.1	18.8
	Total	124.5	40.3	138.9	66.6	162.8	75.6
	% of GDP	1.7%	0.5%	1.9%	0.9%	2.2%	1.0%
Combined	**Total**	264.5	100.0	208.1	120.4	252.2	132.6
	% of GDP	3.6%	1.4%	2.8%	1.6%	3.4%	1.8%

Funding Gap

Market sounding participants indicated that they do not expect a Capex funding gap in the short term (2025–2027) for energy infrastructure investments within the South African market. However, over the medium (2028–2030) to long term (2031–2050), the Capex funding gap is expected to be significant due to various obstacles and limitations. These include unattractive pricing on senior debt, unreliable government energy procurement programmes, and policy uncertainty and instability. Unattractive debt pricing poses a challenge for local investors and banks, as they may become struggle to sell their project exposures by syndicating their debt positions in the secondary market.

The funding gap analysis relied on insights from the market sounding exercise, current public and private spending on energy infrastructure, and Opex and Capex financing requirements derived from technical modelling. The three scenarios were calculated over three periods (2025–2027, 2028–2030, and 2031–2050), with high and low funding attraction alternatives for periods two and three[51]. Capex calculations included grid costs, while Opex costs covered variable and fixed expenses, indicated in 2024 real terms (refer to Table 44). While Opex was considered, the funding gap analysis focused on Capex.

Table 44: Capex Funding Gap per Scenario and (Private) Funding Attraction Alternatives[52] (R'bn p.a., discounted 8% to 2024 real terms, and % of GDP)

	Scenario A (Green Industrialization)		Scenario B (Market Forces)		Scenario C (Business-as-usual)	
2025–2027	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**
Capex gap	12.5 (0.17%)		-58.4 (-0.80%)		-38.1 (-0.52%)	
2028–2030	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**
Capex gap	53.5 (0.73%)	44.0 (0.60%)	-17.4 (-0.24%)	-26.9 (-0.37%)	2.8 (0.04%)	-6.6 (-0.09%)
2031–2050	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**
Capex gap	-9.4 (-0.13%)	-21.2 (-0.29%)	-15.3 (-0.21%)	-27.1 (-0.37%)	-12.1 (-0.16%)	-23.9 (-0.33%)

Given that the assumptions relating to the high and low funding attraction alternatives are the same for each scenario under each period, the extent of the funding gap differences is directly determined by the Capex requirements. Specifically, these include the timing of Capex outlay requirements for the underlying technology mix and the associated learning rates of these sets of technologies.

The Capex funding gap estimations suggest that, due to the high Capex requirements from 2025 to 2030, a notable Capex funding gap could exist under Scenario A (Green Industrialization). However, from 2031 to 2050, no funding gap exists for Scenario A (Green Industrialization). Further-more, no

[51] The low and high funding attraction alternatives indicate the proportion of private finance expected to be attracted by the market from the annual average baseline of R118 billion during the first period (2025 to 2027). These proportions are indicated in brackets. Please note that public funding is then added to the proportional private funding estimation to produce the final Capex secured figure for each period.

[52] The low and high funding attraction alternatives indicate the proportion of private finance expected to be attracted by the market from the annual average baseline of R118 billion during the first period (2025 to 2027). These proportions are indicated in brackets. Please note that public funding is then added to the proportional private funding estimation to produce the final Capex secured figure for each period.

funding gap exists for Scenarios B (Market Forces), or Scenarios C (Business-as-usual) provided adequate levels of private sector funding can be secured over the forecast period.

Effective tariff setting and collections are crucial to recovering operational and maintenance spending. There is a distinct risk that the funding gap could increase further should Eskom and NTCSA be unable to collect sufficient tariff revenues to cover their operational and maintenance expenses, in addition to repaying Capex over the predetermined period (i.e., the WACC). Including Opex, the gap increases to 2.21%–3.60% of GDP (2025–2027) and 2.93%–5.28% (2031–2050). From 2031–2050, Scenario A’s Opex is much lower than the Opex of the other two scenarios; therefore, Scenario A has the lowest total funding gap over the full period.

Market sounding participants also provided several key enablers or catalysts, as well as innovative funding solutions, which may assist in addressing the long-term funding gap. Some examples include enhancing the use of blended finance, increasing asset allocations made by local pension funds, consistent and transparent implementation of energy infrastructure policies and framework, utilizing alternative funding models, unlocking wider secondary market debt participation, developing a pipeline of bankable projects, and facilitating credit enhancement and support from the National Treasury.

Regulatory Review

South Africa's energy policies, such as the White Paper on Energy Policy and the White Paper on Renewable Energy, provide a foundational framework for energy infrastructure and service delivery. However, these policies lack updates and specificity regarding funding mechanisms. The Constitution implies a right to electricity through the right to adequate housing and essential services, placing the responsibility on municipalities to ensure sustainable service provision. Despite recognising the need for substantial investment, the energy sector struggles to balance cost-reflective tariffs and substantial tariff increases due to the absence of developed alternative funding and pricing mechanisms.

The Electricity Regulation Act aims to decentralise and modernise South Africa's energy system, but lacks explicit provisions for funding energy infrastructure, creating a significant gap. The National Energy Act empowers the Minister of Electricity and Energy to introduce regulations promoting investment, but these provisions have not been utilized. Barriers, including inconsistent policies, delays in implementation, and regulatory complexities, hinder progress towards achieving SDG 7.1 and NDP goals. The success of the Electricity Regulation Amendment Act depends on the Government's willingness to implement reforms and publish empowering rules and regulations. A more coherent and supportive regulatory framework is needed to encourage investment in renewable energy and energy-efficient technologies.

The review of international regulatory frameworks reveals that stable and transparent regulatory environments are crucial for driving investment in energy infrastructure. Countries with clear legal and policy frameworks, well-defined tariff structures, and predictable regulatory processes have been more successful in attracting private sector participation. Incentive-based regulations, such as performance-based ratemaking and return-on-equity guarantees, have also played a significant role in promoting investment by ensuring fair and predictable returns for investors.

Additionally, competitive procurement mechanisms, like auctions and tendering processes, have proven effective in reducing costs and increasing investor confidence. Streamlined permitting and approval processes have expedited project development by minimising bureaucratic delays and regulatory uncertainty. Hybrid financing models, leveraging public-private partnerships, have facilitated greater capital inflows by enabling risk-sharing between governments and private investors. Proactive regulatory bodies that engage with industry stakeholders and adapt to evolving market conditions have been more successful in maintaining robust investment in energy infrastructure.

9 Summary of Conclusions

Investment Required and Scenario Options

Scenario A

- **Context:** Scenario A (Green Industrialization) assumes optimistic technology learning rates, lower fuel prices, a higher carbon tax, and a strong alignment with both local and global green industrialization objectives. It also includes a premium on the cost of capital for fossil fuel technologies (10%) and the earliest AQ compliance deadline (2030).
- **Results:** Scenario A involves the largest and most accelerated transition away from coal generation to VRE, BESS, gas, and CCS. This results in the highest up-front capital investment of R1 651 billion for generation; the lowest operation, maintenance, and fuel investment of R1 552 billion; the highest grid capacity investment of R383 billion; but the lowest total system investment of R3 586 billion by 2050. Grid investments comprise 11% of the total system investment, with 53% of these grid investments attributed to distribution collector networks.
- **Emissions:** Scenario A results in the lowest total CO_2 emissions of 2.1 Gt from 2023 to 2050, comfortably achieving the NDC target range for the power sector (120 to 180 Mt/a in 2030). By 2050, emissions are reduced to around 8 Mt/a, which is consistent with net-zero ambitions.
- **Challenges:**
    - High capital investment requirements, particularly for renewables and BESS,
    - Technical and institutional capacity to rapidly deploy and integrate these technologies,
    - Economic impacts of rapid coal decommissioning, and
    - Deployment of CCS from 2035 for Medupi, Kusile, and Majuba (despite CCS currently only being at small-scale readiness globally).

Scenario B

- **Context:** Scenario B (market forces) represents a middle-ground approach, with moderate technology learning rates, medium fuel prices, and a carbon tax trajectory similar to Scenario A. It includes a 5% cost of capital premium for new fossil fuel technologies and mandates AQ compliance by 2035.
- **Results:** This scenario sees a more gradual transition from coal to renewable energy, requiring the lowest generation Capex investment of R1 229 billion; R2 166 billion for operations, maintenance, and fuel; and R262 billion for grid expansion, with a total system investment of R3

657 billion, which is 2% higher than Scenario A. Grid investments represent 7% of the total system investment, with 47% of these investments going to distribution collector networks.

- **Emissions:** CO_2 emissions in 2030 reach 181 Mt/a, which is at the upper end of the NDC target range. Emissions decline significantly to around 51 Mt/a by 2050, potentially within future NDC targets for the power sector.
- **Challenges:**
  - Moderate investment requirements and a more measured infrastructure build-out pace,
  - Delayed CCS deployment (from 2040), with the same technology readiness concerns as in Scenario A, and
  - Need for careful balancing of investment in renewables, BESS, and gas to avoid higher long-term system investments.

Scenario C

- **Context:** Scenario C (Business-as-usual) reflects a pathway with minimal global and local focus on emissions reductions and green industrialization. It is driven by pessimistic technology learning rates, higher fuel prices, and lacks cost of capital premium for fossil fuels. AQ compliance is not mandated.
- **Results:** Scenario C requires R1 446 billion for generation Capex investment; R2 490 billion for operations, maintenance, and fuel (highest estimate); and R231 billion for grid Capex (lowest estimate); resulting in the highest total system investment of R4 166 billion, which is 16% higher than Scenario A, due to persistent reliance on fossil fuels and slow renewable deployment. Grid investments make up only 6% of the total system investment, with 43% of these costs allocated to distribution collector networks.
- **Emissions:** Emissions in 2030 reach 181 Mt/a, which is again at the upper end of the NDC target range. By 2050, emissions remain high at 129 Mt/a, significantly above the net-zero target.
- **Challenges:**
  - High reliance on coal and gas, with no CO_2 emissions or AQ compliance constraints,
  - Higher long-term system costs driven by prolonged fossil fuel dependence, and
  - Limited incentives for renewables and BESS, increasing overall vulnerability to fuel price fluctuations and carbon-related export market barriers.

New power generation capacity: In all scenarios, the largest component of new power generation capacity consists of VRE technologies, such as solar PV and wind, supported by new BESS and gas generation capacity.

Secure and reliable supply: All scenarios achieve a secure and reliable supply of electricity, with no load shedding forecast beyond 2030, assuming the coal fleet meets the forecasted availability levels.

Grid expansion: Key corridors for grid expansion in all scenarios include the western, central, and eastern 765 kV corridors, aligning with Eskom's TDP. The Northern Cape to Free State corridor envisages higher capacity than current plans, reflecting a longer-term focus in this study compared to the medium-term focus of the TDP and Strategic Transmission Corridors.

Funding Gap

- **Funding gap under Scenario A:** The market sounding participants did not expect a funding gap in the short term, based on the premise that R100 billion per annum is required. Due to the high Capex requirements from 2025 to 2030, a notable Capex funding gap could exist under Scenario A (Green Industrialization) over this period. Should South Africa be successful in securing the requisite levels of private sector funding, the estimations indicate no funding gap under Scenario A (Green Industrialization) from 2031 to 2050 and virtually no funding gap at any period for Scenarios B (Market Forces) and Scenario C (Business-as-usual).
- **Tariff setting and collections:** While the tariff setting process includes various considerations, including consumer affordability, if Eskom and NTCSA cannot collect sufficient tariff revenue for expansions, operations, and maintenance, the total funding gap could widen.
- **Public spending and tariff revenues:** Available public energy infrastructure spending and Eskom tariff revenues are insufficient to finance the required new power generation, transmission, and distribution infrastructure. Private sector funding will be necessary, including contributions from donors.
- **Energy regulation and market reform:** The market sounding participants detailed that regulatory, market, and project supply challenges could lead to a decline in private sector funding in the medium to longer term. The Capex funding gap will therefore depend on how effectively South Africa can reform its local energy regulation and market to ensure a pipeline of investible energy infrastructure projects.

Policy and Regulatory Review

- **Fragmented framework:** South Africa's energy-related regulatory landscape is fragmented and underdeveloped compared to the supportive regulatory frameworks in other countries, posing challenges for financing and attracting sustained investment in energy infrastructure.

- **Lack of unified legislation:** The lack of a cohesive legislative framework that more explicitly defines energy infrastructure as a national strategic investment area contributes to procedural ambiguity, which may reduce investor confidence.
- **Political commitment vs regulatory system:** Despite strong political commitment, South Africa's regulatory system is not robust enough to deliver investment at the required pace and scale. For example, although the latest version of the Electricity Regulation Act has been adopted, the supporting regulatory framework to establish the wholesale market and increase energy infrastructure tax incentives is still lacking.
- **De-risking energy projects:** South Africa lacks effective mechanisms to de-risk private sector investments in energy projects, such as government-backed guarantees and blended finance facilities, which are crucial for attracting large-scale investment.
- **International best practices:** Countries like Chile and India have adopted robust legal frameworks that enable IPPs and provide regulatory certainty, which South Africa can learn from. However, South Africa’s adoption of the ITP mechanism marks a significant step in advancing energy infrastructure development, building on the proven success of the REIPPP in attracting investment and enhancing grid capacity.
- **Integrated planning:** Successful jurisdictions use long-term infrastructure planning legislation supported by independent institutions to identify priorities, coordinate stakeholders, and facilitate investment.

10 Summary of Recommendations

Funding Required and Scenario Options

- **Scenario A** is consistent with a local and global green transition, presents the best option for exports (considering regulations such as CBAM), meets the NDC targets, and does so with the lowest total system investment[53]. Subject to assessment of the socio-economic impact of Scenario A (which will be included in a supplementary report) and the realization of the relevant local and global pathway assumptions, such as renewable energy technology learning rates, it is recommended to pursue the technology transition, energy mix, and associated investment requirements of Scenario A, as summarised in Table 28 in Section 4.8. Since achieving Scenario A is conditional on the realization of the local and global pathway assumptions relevant to this scenario, the Government should pursue policy decisions that enable this pathway and its associated assumptions.
- **Scenario B** is premised on a local and global environment that is less focused on a green transition. As a result, its key drivers differ from those of Scenario A, for example, technology learning rates (for VRE and BESS) are less optimistic, and fuel prices are higher. The cost of capital for new fossil fuel generation is also closer to that of renewable energy. In this environment, Scenario B represents an energy mix with the lowest investment requirement and partially exceeds South Africa’s NDC target. While the annual average Capex investment is lower than Scenario A, the total system investment is higher. If the local and global pathway assumptions shift towards Scenario B, a policy space may well be created that justifies selecting a technology transition, energy mix, and associated investment requirements aligned with Scenario B, as summarised in Table 29 in Section 4.8. The major difference between Table 28 and Table 29 is the coal capacity. Despite the economic rationale justifying Scenario B, South Africa may still want to align its policy choices with Scenario A in response to the wider climate impacts, which result in Southern Africa warming at twice the global rate (Scholes and Engelbrecht, 2021).
- **Scenario C** reflects an abandonment of South Africa’s NDC commitments due to a breakdown in global alignment and or acute economic cost challenges, but retains a focus on electricity production through least cost and security of supply. With the local and global environment no longer focused on a green transition, key drivers from scenarios A and B differ, e.g., technology learning rates (for VRE and BESS) are pessimistic, fuel prices are even higher, and the cost of

[53] *Total system investment = Total generation Capex + Total generation Opex (including fuel) + Total transmission (including distribution collector networks) Capex, discounted at 8% in 2024 real terms.*

capital for new fossil fuel generation is equal to that of renewable energy. While the annual average Capex investment remains lower than Scenario A, the total system investment is the highest of all scenarios. If the local and global pathway assumptions shift towards Scenario C, a policy space may develop that justifies selecting a technology transition, energy mix, and associated investment requirements aligned with Scenario C, as summarised in Table 30 in Section 4.8. Despite the economic rationale justifying Scenario C, South Africa may still want to align its policy choices with scenarios A or B in response to wider climate impacts resulting in Southern Africa warming at twice the global rate (Scholes and Engelbrecht, 2021).

The following broad recommendations apply across the range of pathways and related scenarios considered in this study:

- **Significant expansion of VRE technologies**: Focus on expanding VRE as part of the least-cost energy solution, supported by various mitigation modelling exercises for South Africa.
- **Incorporate gas and battery storage to support VRE technologies**: Include gas-fired power plants and BESS to provide necessary support and flexibility for VRE capacity. Gas is suitable for longer stabilization periods, while BESS is effective for shorter periods. Avoid shifting coal baseload to gas baseload. Gas should be dispatched at relatively low-capacity factors to support variability in VRE output.
- **No new coal and nuclear plants**: Avoid new coal and nuclear capacity in the least-cost energy mix, as indicated by multiple studies, including this one.
- **AQ retrofits only for plants with longer remaining lifetimes**: Decommission coal plants with shorter remaining life instead of deploying AQ retrofits. Conduct a thorough cost-benefit analysis before investing in AQ retrofits.
- **Investigate and monitor the feasibility of CCS technology**: Monitor CCS technology for future feasibility and cost-effectiveness. Its successful deployment depends on global adoption rates and maturity.
- **Maintain existing infrastructure**: Ensure existing coal fleet meets availability targets and transmission infrastructure is reliable to achieve energy security and reliability.
- **Decentralized energy systems**: Implement renewable energy-based microgrid systems for rural communities to improve the quality of life and create job opportunities.
- **Co-locate renewable energy generation infrastructure with demand**: Reduce transmission losses and improve energy efficiency by co-locating renewable energy infrastructure with demand centres like industrial parks and urban areas.
- **Monitor disruptive technologies**: Monitor the development of new technologies in the electricity sector, as discussed in Appendix E.

Closing the Funding Gap

- **Effectively and strategically use (catalytic) public sector funding and guarantees:** To increase co-investments by the private sector, it will be necessary to reduce risks without subsidizing private sector profits. Long-term fiscal policy certainty, a predictable regulatory environment, and well-designed institutional mechanisms such as the Infrastructure Fund, can all contribute by increasing investor confidence and leveraging additional capital through Public-Private Partnerships, Blended Finance, and International Aid and Donor Funding.
- **Expedite regulatory and market reform:** Addressing the items below, as highlighted by the market sounding participants, could assist in attracting investment and reducing the funding gap over the long term for investment in the South African energy infrastructure market:
  - Debt instruments and products must be repriced to ensure liquidity and long-term participation from the secondary market, given the local commercial banking sector's exposure limits.
  - Improved clarity and consistency when implementing programmes (such as the coal fleet decommissioning schedule) to ensure a long-term pipeline of bankable projects is developed.
  - National Treasury-backed guarantees or similar guarantee-type vehicles, such as the World Bank Guarantees Program, with an appropriate mix of grant, concessional (i.e., climate finance), and market-related funding to reduce the overall cost of capital. These guarantees will unlock private sector capital, and assist in the development of the pipeline of bankable projects.
  - From a market risk perspective, the development of a wholesale energy market should be finalized to create liquidity and pricing certainty, which would encourage additional market participation from power producers, consumers, and financial institutions.
  - Implement policies and frameworks, and develop bankable commercial structures with suitable guarantees, to encourage the funding and implementation of the transmission programme.
  - Reindustrialization and capacitation of technical skills to support the energy infrastructure market, particularly for the EPC contractors and manufacturers.
  - Improved coordination of various public stakeholders to ensure projects can progress to bankability and implementation.
  - Improve Eskom's ability to process the substantial number of BQ applications.
  - Promotion and education of pension funds relating to alternative asset classes, such as the infrastructure sector, to encourage additional capital formation and allocations from the private sector from 2% to potentially 5% to align with international norms.

Policy and Regulatory Enhancement

- **Renewable energy fund:** Introduce a renewable energy surcharge, similar to Germany's EEG, to fund clean energy projects and ensure fairness for low-income households and equitable cost-sharing across all users.
- **Tax incentives:** Offer tax breaks like the US’s ITC and PTC to lower upfront costs and reward energy production. Introduce incentives aimed at utility-scale deployment to drive large-scale investment. Several tax incentives remain under the Income Tax Act 58 of 1962 (as amended), that can be used for energy infrastructure development, such as Section 12B: Capital Allowance for Renewable Energy Assets and Section 11(e) of the Act, which relates to the depreciation (wear and tear) of plants, machinery, and equipment used in the production of income.
- **Targeting mechanisms:** Mandate municipalities to source a set percentage of electricity from renewables. Use RECs to ensure compliance and incentivise investments.
- **Pricing and returns:** Create capacity and ancillary services markets to secure a reliable power supply and grid stability. Provide fair, transparent incentives for availability, generation, and stability services.
- **Deemed energy payments:** Protect IPPs against network risks by enforcing NERSA rules. Adopt models like Morocco’s Grid Access Agreements to ensure compensation for undelivered energy due to grid issues.
- **Grid Access Unit (GAU):** Move the GAU from Eskom Distribution to an independent entity like the NTCSA. Address conflicts of interest and improve efficiency in delivering connections and projects. Ensure smoother project implementation by reducing delays in technical designs and user requirements for grid connections.

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Annexures

Annexure A: Reference Energy System (RES) Diagram

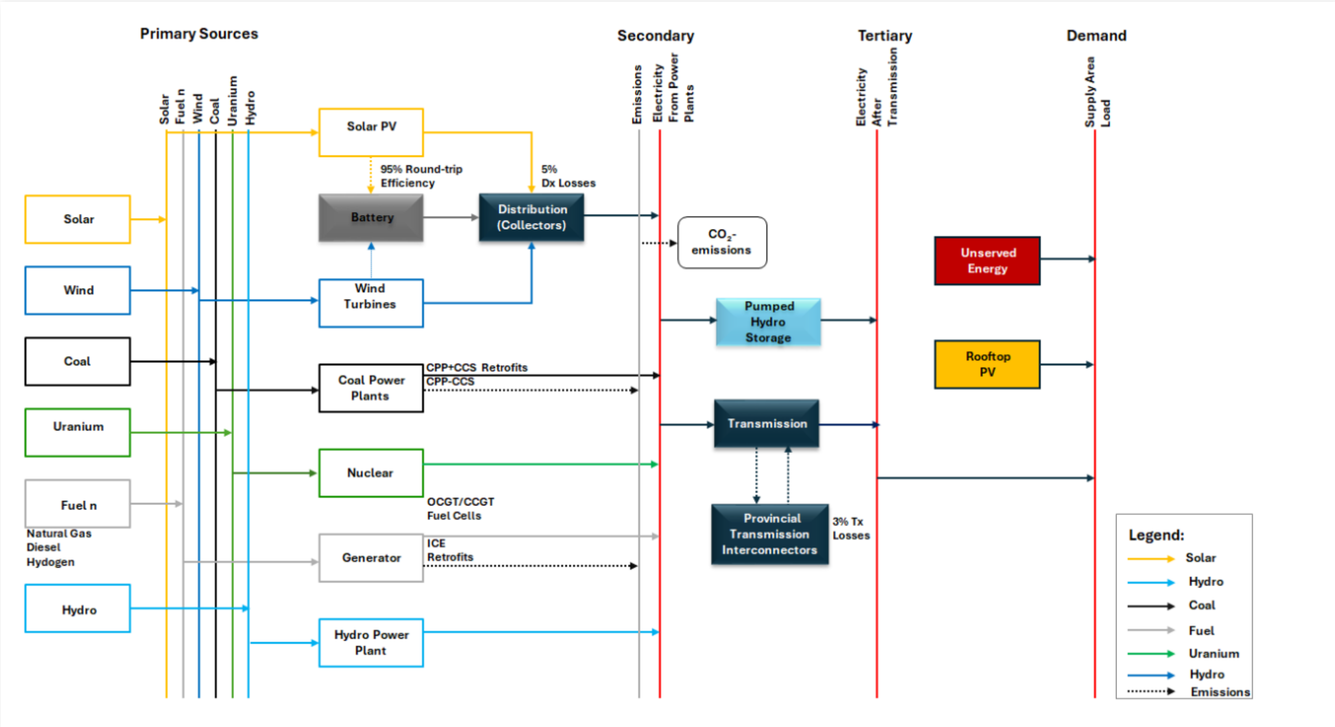


Figure 57: Reference Energy System (RES) Diagram

Annexure B: Power System Analysis

The objective of the power system analysis is to quantify the transmission evacuation capacity that is used as an input in energy modelling. This analysis also tests the ability of the planned infrastructure to collect the proposed generation capacity from various supply areas and transmit that power to the load centre. This test confirms that the proposed grid strengthening is practical and that the outcome of the grid costs is realistic. Note that the NTCSA is responsible for developing the detailed 10-year Transmission Development Plan (TDP), and the current analysis does not seek to replicate or replace the TDP. The primary objective is to assess whether the cost of the developed grid is realistic, as this determines the electricity funding gap.

i. Power System Model Setup

The modelling for this task was performed using the Power System Simulator for Engineering (PSSE) software, which is also used by the NTCSA for network modelling.

The power system analysis assessed the transmission network's capability to collect and transfer power from the net-exporting supply areas to the net-importing supply areas. The study only assesses the steady-state network capability.

The key analyses conducted in the PSSE software include:

- Steady-state analysis, including power transfer limit analysis on the main transmission corridors,
- Evaluation of equipment thermal loading, and
- Evaluation of steady-state voltage regulation.

Note that this study did not include transient stability studies.

ii. Inputs to Power System Modelling

The initial approach was to source the Eskom TDP PSSE case file and use that as a base for modelling the future network scenario. However, as Eskom case files were not available, publicly available information from the TDP, GCCA, and other sources was used to model the South African transmission network to align with the TDP2032. The transmission network was modelled within the PSSE simulation tool to reflect the projected status of the South African energy grid in 2032.

The network model was developed and benchmarked against the GCCA 2025 before conducting any studies. The network model was internally reviewed against the following:

- Network connectivity,
- Generation and loading schedule,
- Voltage levels at selected substations,
- Fault levels at selected substations,
- Network operational configuration, and

- Network losses.

iii. Power System Model Assumptions and Limitations

- The network analysis was conducted using the model development process described above and incorporating best practices on the impact of grid integration of renewable energy, while considering the current technical constraints within the South African electrical network.
- The renewable generation facilities and energy storage systems were modelled as single (aggregated) generators per substation, representing typical inverter technology available in the market today.
- Where network component information is not readily available, typical values were assumed, or generic models were utilized.
- Renewable energy and BESS facilities are represented as an equivalent PQ generation source, with applicable real and reactive power values that correspond to the MVA of the plant and its operating power factor limits.
- Modelling was steady state only, not dynamic.

iv. Power System Model Outputs

- Analysis and results obtained over the study period for the following study years: 2025, 2030, 2040, and 2050;
- Evaluation of the capacities of the transmission networks evacuating power from the generation sources (exporting supply areas) was assessed for 2025, 2030, and 2035;
- Evaluation of the impact of VRE and BESS;
- Assessment of network strengthening options;
- Determination of priority projects and investments;
- Estimation of the Capex for the transmission and distribution investments up to 2050; and
- Geographical location of the transmission and generation build.

Table 45 shows the results of the corridor transfer limits, while Figure 58 shows a geographical view of the transmission lines that form the corridors. The transfer limits were modelled with an N-1 contingency that simulated the loss of critical equipment in the system, such as the loss or failure of a transformer or transmission line.

Table 45: Power System Model Outputs

Corridor	Year	SIL (N–1)	Loadability (N–1)	PV transfer (N–1)
WC to HC	2025	1 737 MW	2 305 MW	1 919 MW with a contingency of losing Gamma Kappa 765 kV line
	2030	2 690 MW	3 655 MW	3 772 MW with a contingency of losing Kappa Sterrekus 765 kV line
	2035	2 690 MW	3 655 MW	4 545 MW with a contingency of losing Gamma Kappa 765 kV line
WC to NC	2025	536 MW	802 MW	714 MW with a contingency of losing Hydra – Kronos 400 kV line
	2030	536 MW	802 MW	655 MW with a contingency of losing Upington – Ferrum 400 kV line
	2035	1 072 MW	1 298 MW	809 MW with a contingency of losing Juno – Sterkus 765 kV line
HC to EC	2025	465 MW	894 MW	1 104 MW with a contingency of losing Poseidon – Delphi 400 kV line
	2030	969 MW	1 873 MW	293 MW with a contingency of losing Perseus – Gamma 765 kV line
	2035	2 477 MW	3 798 MW	1 050 MW with a contingency of losing Iziko – Poseidon 400 kV line 1
HC to FS	2025	3 362 MW	4 961 MW	4 409 MW with a contingency of losing Neptune – Delphi 400 kV line
	2030	3 362 MW	4 961 MW	4 836 MW with a contingency of losing Hydra 2000 MVA 765/400 kV transformer
	2035	4 850 MW	6 808 MW	5 460 MW with a contingency of losing Theseus – Perseus 400 kV line
HC to NC	2025	540 MW	745 MW	1 137 MW with a contingency of losing Hydra 2000 MVA 765/400 kV Transformer
	2030	540 MW	745 MW	1 628 MW with a contingency of losing Ferrum – Upington 400 kV line
	2035	540 MW	745 MW	1 136 MW with a contingency of losing Hydra – Kronos 400 kV line

Corridor	Year	SIL (N–1)	Loadability (N–1)	PV transfer (N–1)
NC to NW	2025	337 MW	703 MW	694 MW with a contingency of losing Ferrum 250 MVA 400/132 kV transformer
	2030	763 MW	1 648 MW	1 405 MW with a contingency of losing Hermes – Mookodi 400 kV line
	2035	763 MW	1 648 MW	2 308 MW with a contingency of losing Umtu – Mercury 765 kV line
NC to FS	2025	318 MW	495 MW	486 MW with a contingency of losing Kronos – Hydra 400 kV line
	2030	635 MW	992 MW	1 019 MW with a contingency of losing Beta – Boundary 400 kV line
	2035	1 219 MW	2 056 MW	1 891 MW with a contingency of losing Perseus – Mercury 765 kV line
EC to FS	2025	374 MW	645 MW	555 MW with a contingency of losing Neptune – Delphi 400 kV line
	2030	374 MW	645 MW	1 295 MW with a contingency of losing Neptune – Vuyani 400 kV line
	2035	374 MW	645 MW	710 MW with a contingency of losing Dorper – Delphi 400 kV line
EC to KZ	2025	529 MW	677 MW	533 MW with a contingency of losing Mookodi – Ferrum 400 kV line
	2030	624 MW	818 MW	942 MW with a contingency of losing Grass – Gamma 765 kV line
	2035	2 455 MW	1 786 MW	2043 MW with a contingency of losing Ariadne – Eros 400 kV line
FS to MP	2025	4 803 MW	6 144 MW	5 531 MW with a contingency of losing Mercury – Zeus 765 kV line
	2030	4 803 MW	6 144 MW	6 616 MW with a contingency of losing Mercury – Zeus 765 kV line
	2035	6 582 MW	8 456 MW	9 169 MW with a contingency of losing Perseus – Zeus 765 kV line
FS to GP	2025	248 MW	589 MW	528 MW with a contingency of losing Makalu – Everest 275 kV line

Corridor	Year	SIL (N–1)	Loadability (N–1)	PV transfer (N–1)
	2030	248 MW	589 MW	570 MW with a contingency of losing Snowdon – Everest 275 kV line
	2035	248 MW	589 MW	820 MW with a contingency of losing Snowdon – Everest 275 kV line
NW to LP	2025	4 204 MW	9 462 MW	5027 MW with a contingency of losing Matimba – Spitskop 400 kV line
	2030	4 204 MW	9 462 MW	5027 MW with a contingency of losing Matimba – Spitskop 400 kV line
	2035	4 204 MW	9 462 MW	5027 MW with a contingency of losing Matimba – Spitskop 400 kV line
GP to MP	2025	5 215 MW	9 461 MW	6 008 MW with a contingency of losing Hera 800 MVA 400/275 kV Transformer
	2030	5 536 MW	10 212 MW	6 008 MW with a contingency of losing Hera 800 MVA 400/275 kV Transformer
	2035	5 536 MW	10 212 MW	4 811 MW with a contingency of losing Grootvlei – Hera 400 kV line
GP to NW	2025	2 580 MW	5 133 MW	2574 MW with a contingency of losing Lulamisa – Pluto 400 kV line
	2030	2 580 MW	5 133 MW	2574 MW with a contingency of losing Lulamisa – Pluto 400 kV line
	2035	2 580 MW	5 133 MW	1972 MW with a contingency of losing Mercury – Midas 400 kV line
GP to LP	2025	316 MW	496 MW	496 MW with a contingency of losing Borutho Silimela 400 kV line
	2030	316 MW	496 MW	496 MW with a contingency of losing Borutho Silimela 400 kV line
	2035	316 MW	496 MW	256 MW with a contingency of losing Tabor Witkop 275 kV line
MP to LP	2025	1 163 MW	1 788 MW	1 156 MW with a contingency of losing Duvha – Manogeng 400 kV line
	2030	1 785 MW	2 642 MW	1 118 MW with a contingency of losing Duvha – Manogeng 400 kV line

Corridor	Year	SIL (N–1)	Loadability (N–1)	PV transfer (N–1)
	2035	1 785 MW	2 642 MW	1 182 MW with a contingency of losing Foskor Spencer 400 kV line
KZ to MP	2025	4 152 MW	6 971 MW	6032 MW with a contingency of losing Ingula – Majuba 400 kV line
	2030	4 152 MW	6 971 MW	6032 MW with a contingency of losing Ingula – Majuba 400 kV line
	2035	4 152 MW	6 971 MW	5272 MW with a contingency of losing Majuba – Umfolozi 400 kV line

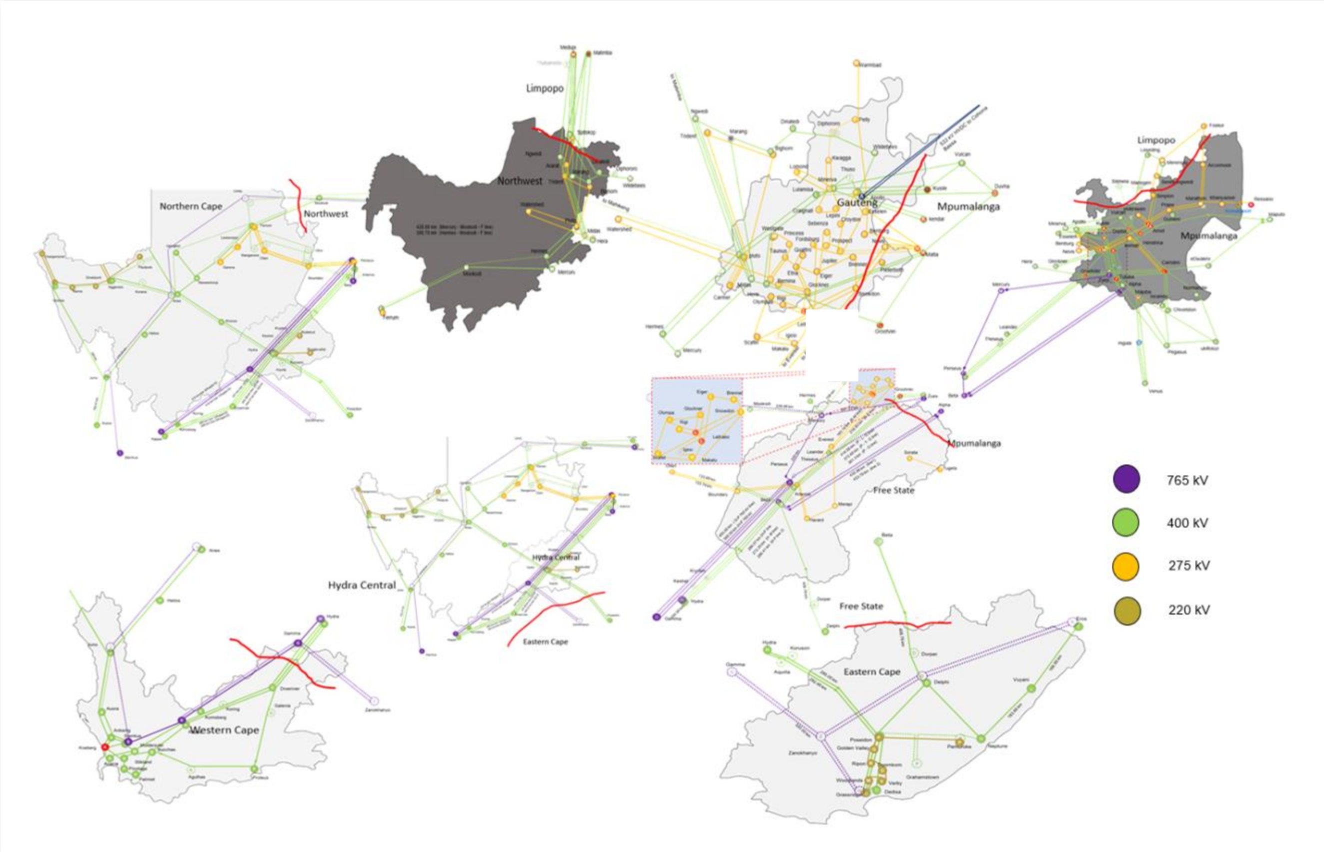


Figure 58: South African Transmission Corridors

Annexure C: Transmission Infrastructure Investments Breakdown

As described in the methodology section of this report (Section 4.2), the transmission grid was modelled using a 'copper plate' approach post 2030, allowing the generation built to be determined by the generation cost. This approach was based on the understanding that the grid expansion cost is a fraction of the generation cost, thus, generation was allowed to dictate the grid strengthening needs. As a result, the outcome of the energy modelling was the transmission grid expansion requirements for scenarios A, B, and C.

Table 46 shows the additional required transmission corridor capacity by 2050 in MW. The linear corridors with the largest grid capacity strengthening requirements are the Western Cape – Hydra Central – Free State – Gauteng / Mpumalanga corridor, and the Western Cape – Northern Cape – North West – Gauteng corridor. A combination of the 765 kV and 400 kV lines is required to unlock this capacity. This study did not consider the high-voltage direct current[54] (HVDC) technology due to limited knowledge of the costing assumptions. The NTCSA will likely include HVDC technology in its future TDPs once this technology design and the costing are well understood.

[54] High-voltage direct current (HVDC) is a technology capable of transmitting electricity over long distances using direct current (DC) instead of alternating current (AC).

Table 46: Transmission Capacity Requirements for Scenarios A, B, and C

From	To	A (MW)	B (MW)	C (MW)
Western Cape	Hydra Central	6 964	6 732	7 265
Hydra Central	Eastern Cape	11 114	6 819	3 034
Hydra Central	Northern Cape	2 466	0	1 693
Hydra Central	Free State	17 592	15 486	18 835
Free State	Mpumalanga	5 258	7 186	0
Free State	Gauteng	20 100	20 100	19 100
Northern Cape	North West	13 125	11 749	11 677
North West	Gauteng	0	24 807	24 688
Mpumalanga	Gauteng	20 000	12 027	20 000
Limpopo	North West	23 700	29 071	28 490
Limpopo	Mpumalanga	4 359	344	258
Western Cape	Northern Cape	5 275	5 275	5 250
Eastern Cape	Free State	10 022	8 357	5 596
Limpopo	Gauteng	22 170	28 635	30 000
Northern Cape	Free State	15 753	11 722	5 271

Table 47 records the transfer limit assumptions for the transmission lines. In summary, the 400 kV single circuit line is assumed to have a transfer limit of 1 000 MW when compensated, and the 765 kV single circuit line is assumed to have a transfer limit of 2 500 MW when compensated over long distances (> 500 km).

Table 47: Transfer Limit Assumptions for Transmission Lines

Voltage (kV)	Number of Conductors	Conductor	Capacity @ 50C (MVA)	Capacity @ 75C (MVA)	SIL (MW)	Compensated (MW)
400	3	Tern	1 260	1 800	900	1 000
765	4	Tern	3 200	4 800	2 200	2 500

Table 48 shows the cost assumptions for the transmission stations and the associated usable capacities or utilization. The main transmission stations (MTS) collecting distributed renewable energy plants are assumed to have an average utilization of 70%, where other MTS will be fully utilized (100%) and others underutilized (50%). The assumption for larger dispatchable plants, such as OCGT or CCGT, is that the MTS are sized for the power plant's capacity, and thus there will be 100% utilization.

Furthermore, the MTS collecting distributed renewable energy plants have assumed the N-1 level of transformation capacity, with a maximum of 4 x 500 MVA, 400/132 kV.

Table 48: Cost Assumptions for Transmission Stations

Resource	MTS	Capacity (MW)	Utilization (%)	Used Capacity (MW)
PV	400/132 kV, 4 x 500 MVA	1 425	70%	997.5
Wind	400/132 kV, 4 x 500 MVA	1 425	70%	997.5
Nuclear	400/33 kV, 5 x 500 MVA	1 900	100%	1 900
Gas	400/33 kV, 5 x 500 MVA	1 900	100%	1 900
PHS	400/33 kV, 5 x 500 MVA	1 900	100%	1 900

Table 49 shows the sub-transmission collector network cost assumption. It is assumed that the PV and wind power plants connect to the transmission station with the average sub-transmission line length of 30 km and BESS with an average line length of 20 km. The assumed sub-transmission line configuration is the 132 kV Twin-Tern single circuit line at the cost of R8 million per km. Each PV, wind and BESS facility is assumed to connect via a metering station. The collector stations are assumed to be shared by multiple generation and storage facilities.

Table 49: Cost Assumptions for the Sub-Transmission Collector Network

Technology	MEC (MW)	Distance (km)	132 kV TwinTern	Dedicated Metering Station	Shared Collector Station	Cost (R'mn)	R'mn/MW
BESS	100	20	8	45	22.5	227.5	2.275
VRE (PV & Wind)	100	30	8	45	11.25	296.25	2.9625

The total transmission and sub-transmission grid costs for scenarios A, B, and C are indicated in Table 50.

Table 50: Grid Cost Summary (R'mn)

Costing Item	Scenario A	Scenario B	Scenario C
Transmission Backbone	R 162 851.33	R 160 386.67	R 162 084.92
Transmission Substation	R 196 100.00	R 126 000.00	R 113 800.00
Transmission Lines	R 71 880.00	R 46 080.00	R 41 520.00
Distribution Collector Network	R 490 917.15	R 297 747.65	R 237 838.83
Total Grid Expansion Cost (excluding refurbishment)	**R 921 748.48**	**R 630 214.32**	**R 555 243.75**

Annexure D: Energy Modelling Sensitivity Analysis

i. Sensitivity 1: No growth by 2040

Question: What is the capital cost required to replace the decommissioned coal fleet by 2040 assuming a zero increase in energy demand?

The undiscounted, cumulative capital cost required for new energy generation is R1 262 billion by 2030, R1 801 billion by 2035, R2 670 billion by 2040, i.e., an average of R178 billion per annum.

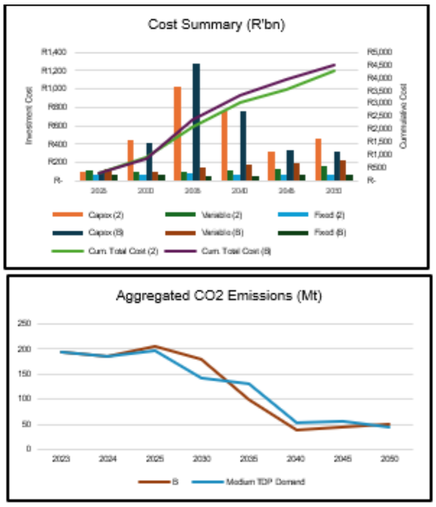
SENSITIVITY	1	B	Delta
VRE Capacity (GW)	53	97	-44
BESS (GW)	18	33	-15
Dispatchable Capacity (GW)	63	82	-19
Total Generation Cost (R'bn)	3,183	4,508	-1,325
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 59: Sensitivity 1 No Growth to 2040

ii. Sensitivity 2: Medium Demand TDP

Question: What happens if the growth rate in demand is reduced from IRP 2023 Ref Case (CAGR: 2.1%) to Medium TDP (CAGR: 1.9%)?

The Medium Demand TDP scenario is approximately 5% less than the IRP 2023 Ref Case. As a result, the model builds approximately 5% less new power generation capacity which reduces the total generation costs by approximately 5%. Most other trends remain similar to Scenario B.



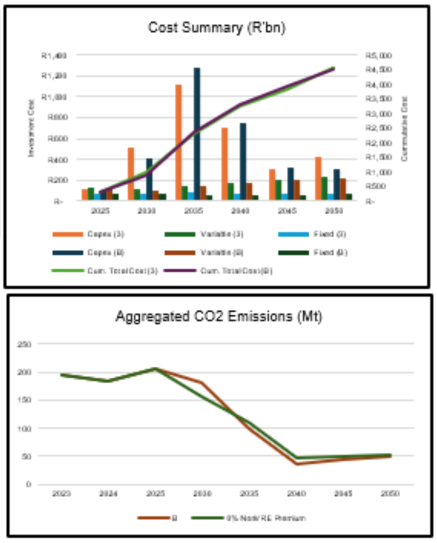
SENSITIVITY	2	B	Delta
VRE Capacity (GW)	92	97	-4
BESS (GW)	31	33	-2
Dispatchable Capacity (GW)	77	82	-5
Total Generation Cost (R'bn)	4,251	4,508	-256
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 60: Sensitivity 2 Medium TDP Demand

iii. Sensitivity 3: 0% Premium on Fossil Fuel Generation Technologies

Question: What happens if one removes the 5% Capex premium applied to fossil fuel technologies?

Removing the 5% Capex premium on fossil fuel technologies results in additional 1 GW of new gas generation being built in 2030, compared to Scenario B. By 2050, the generation capacity and energy mix are much the same as Scenario B.



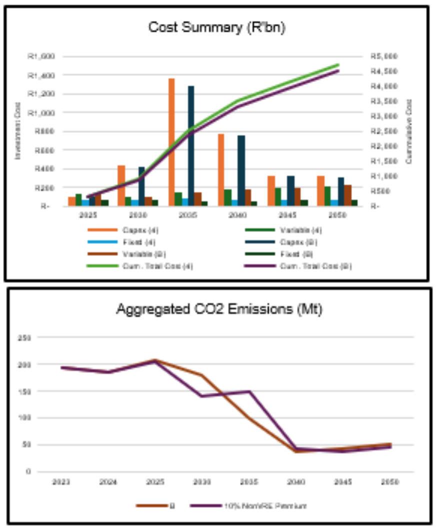
SENSITIVITY	3	B	Delta
VRE Capacity (GW)	95	97	-2
BESS (GW)	33	33	0
Dispatchable Capacity (GW)	82	82	0
Total Generation Cost (R'bn)	4,555	4,508	47
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 61: Sensitivity 3 0% Non-VRE Premium

iv. Sensitivity 4: 10% Premium on Fossil Fuel Generation Technologies

Question: What happens if one increases the Capex premium applied to fossil fuel technologies to 10%?

Raising the Capex premium on fossil fuels 10% shifts some of the new power generation investment away from new gas and towards new renewables and energy storage. Total generation costs increase by approximately 4% until 2050.



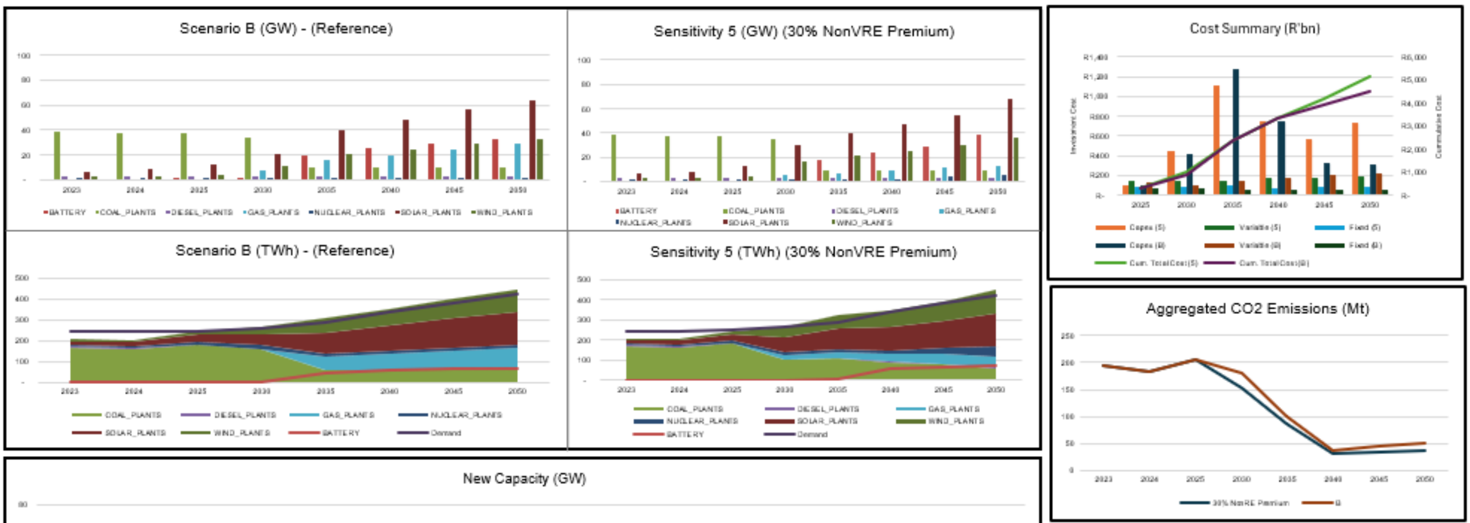
SENSITIVITY	4	B	Delta
VRE Capacity (GW)	100	97	3
BESS (GW)	33	33	0
Dispatchable Capacity (GW)	76	82	-5
Total Generation Cost (R'bn	4,708	4,508	201
CO_2 Emissions (Gt)	3.0	3.0	0.0

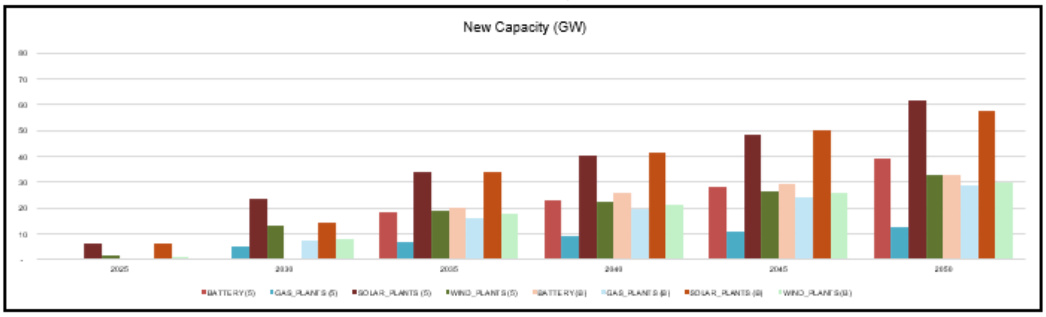
Figure 62: Sensitivity 4 10% Non-VRE Premium

v. Sensitivity 5: 30% Premium on Fossil Fuel Generation Technologies

Question: At what Capex premium applied to fossil fuel technologies will new nuclear capacity be deployed?

The Capex premium applied to fossil fuel technologies was increased at 10% increments. The tipping point where the Capex premium on fossil fuels results in deployment of new nuclear capacity is between 20% and 30%. Based on the demonstration calculation in Table 11 of the report, using the same assumptions, 20% and 30% Capex premiums translate to an all-in risk premium on debt of 6.15% and 8.01%, respectively. CO_2 emissions are reduced to 2.6 Gt.





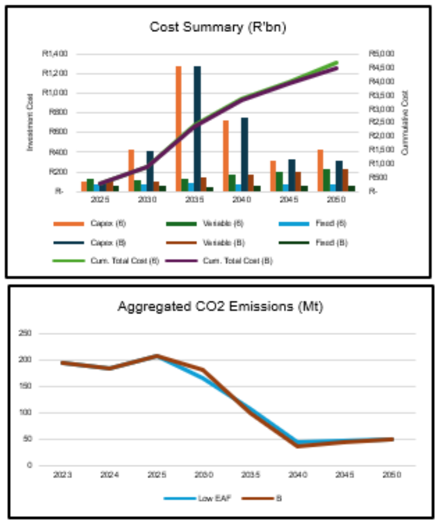
SENSITIVITY	5	B	Delta
VRE Capacity (GW)	104	97	7
BESS (GW)	39	33	6
Dispatchable Capacity (GW)	75	82	-7
Total Generation Cost (R'm)	5,159	4,508	651
CO2 Emissions (Gt)	2.6	3.0	-0.4

Figure 63: Sensitivity 5 30% Non-VRE Premium

vi. Sensitivity 6: Low EAF

Question: What happens if the EAF of the Eskom coal fleet (excluding Medupi and Kusile coal plants) remains at 60% and never improves?

If Eskom's coal fleet maintains a 60% EAF, the system will compensate by dispatching more gas, mostly in 2030, which results in a higher total generation cost. Beyond 2030, the coal fleet follows a similar decommissioning pathway as Scenario B, and the energy mix is much the same.



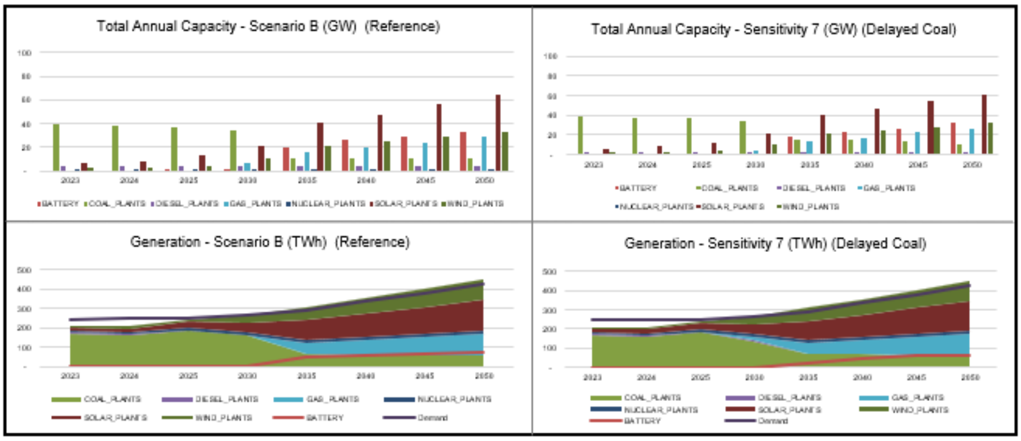
SENSITIVITY	6	B	Delta
VRE Capacity (GW)	96	97	-1
BESS (GW)	33	33	0
Dispatchable Capacity (GW)	81	82	-1
Total Generation Cost (R'bn)	4,688	4,508	180
CO2 Emissions (Gt)	2.7	3.0	-0.3

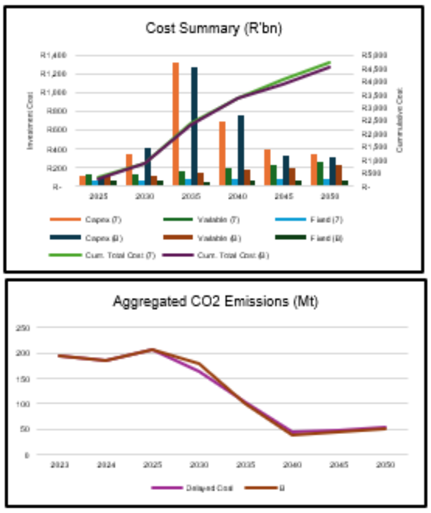
Figure 64: Sensitivity 6 Low EAF

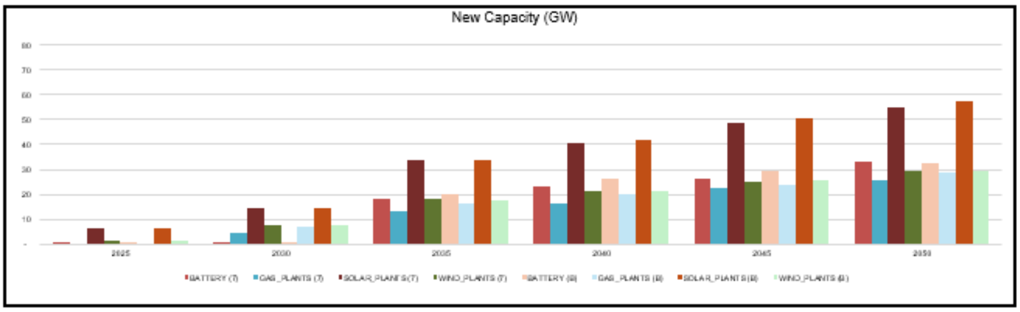
vii. Sensitivity 7: Delayed Coal Decommissioning

Question: What happens if the Eskom coal fleet decommissioning dates are extended?

Extending the life of Eskom’s coal plants and forcing them to dispatch until their end of life, reduces near-term investment in renewables and gas, leading to higher total generation cost. By 2050, the capacity build and energy mix are similar to Scenario B. However, gas dispatches less to keep CO_2 emissions constrained to the 3.0 Gt budget.







SENSITIVITY	7	B	Delta
VRE Capacity (GW)	94	97	-3
BESS (GW)	33	33	0
Dispatchable Capacity (GW)	80	82	-2
Total Generation Cost (R'bn)	4,732	4,508	224
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 65: Sensitivity 7 Delayed Coal Decommissioning

viii. Sensitivity 8: No AQ Retrofits in 2035

Question: What happens if AQ retrofits are never mandated?

Without mandated AQ retrofits, more coal remains online for longer and total generation costs are reduced since the cost of AQ retrofits are not incurred. VRE and BESS contribute more of the energy mix from 2035 onwards to keep the CO_2 emissions within the 3.0 Gt budget. Similar generation mix and capacity build by 2050.

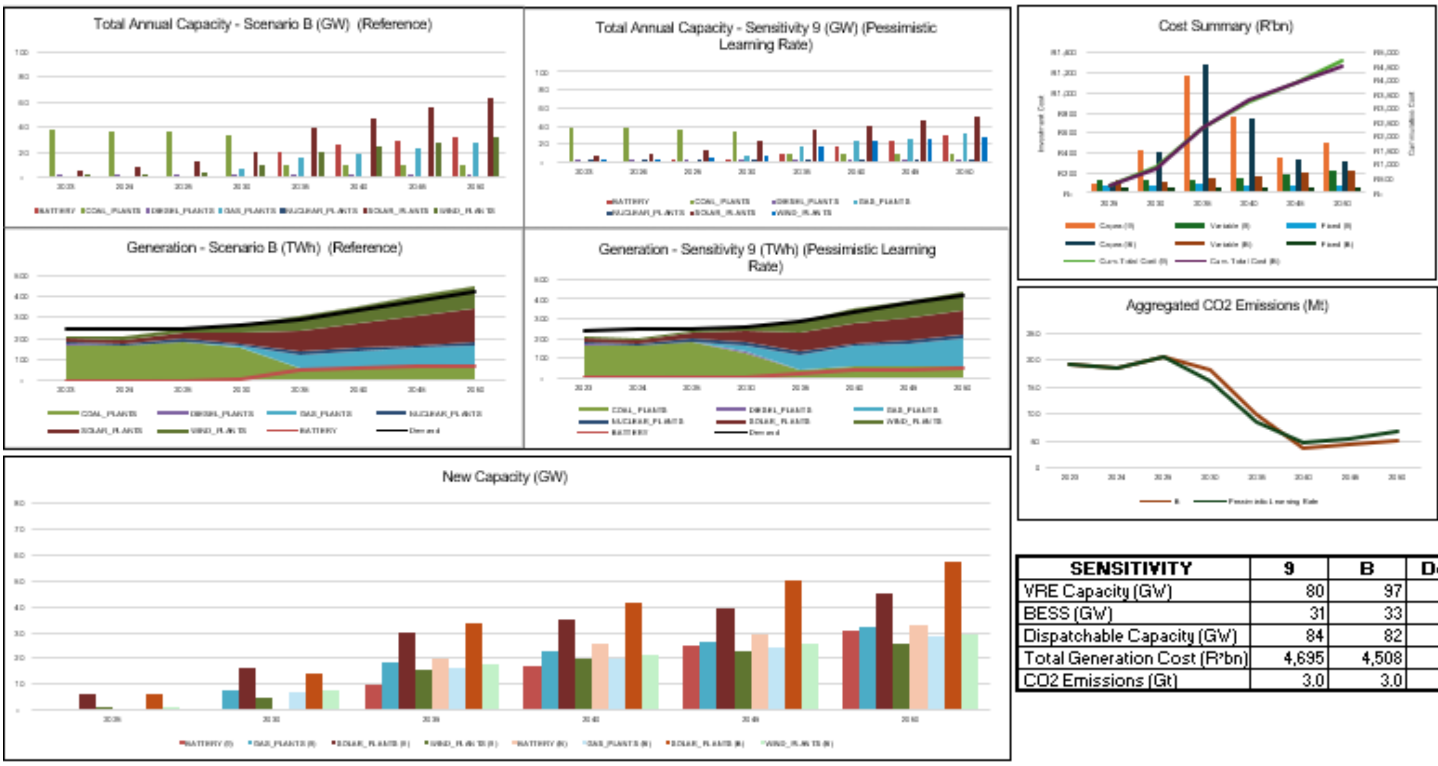
SENSITIVITY	8	B	Delta
VRE Capacity (GW)	96	97	-1
BESS (GW)	33	33	0
Dispatchable Capacity (GW	80	82	-1
Total Generation Cost (R'bn	4,420	4,508	-88
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 66: Sensitivity 8 No AQ Retrofits in 2035

ix. Sensitivity 9: Pessimistic Learning Rate

Question: What happens if one adopts the pessimistic learning rates for VRE and BESS technologies?

Higher technology costs for renewables and BESS result in greater reliance on gas and significantly less new capacity of solar, wind, and energy storage. Coal dispatches are reduced between 2025 and 2035 to keep CO_2 emissions within the 3.0 Gt budget constraint. Total generation costs increase.



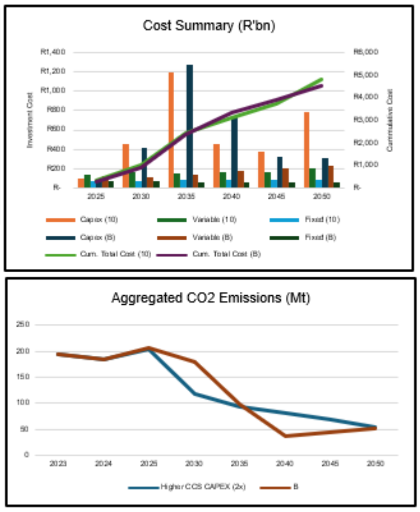
SENSITIVITY	9	B	Delta
VRE Capacity (GW)	80	97	-16
BESS (GW)	31	33	-2
Dispatchable Capacity (GW)	84	82	2
Total Generation Cost (R'bn)	4,695	4,508	187
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 67: Sensitivity 9 Pessimistic Learning Rate

x. Sensitivity 10: Higher CCS Capex (2x)

Question: At what Capex cost is CCS no longer selected in the energy mix? Results shown are for 2x CCS Capex cost

The tipping point where CCS is no longer selected is between 1.5 and 2 times the base cost. At double the base cost, CCS is no longer deployed with renewables and gas completely replaces the phased-out coal capacity by 2050. New renewable energy sources are implemented sooner to compensate for the additional CO_2 emissions from coal plants in later years, to adhere to the 3.0 $GtCO_2$ budget constraint.



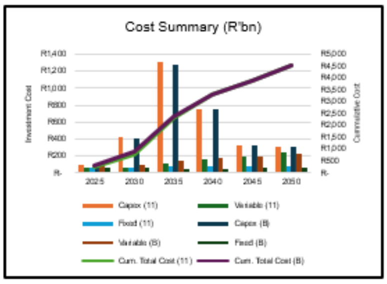
SENSITIVITY	10	B	Delta
VRE Capacity (GW)	117	97	20
BESS (GW)	40	33	7
Dispatchable Capacity (GW)	78	82	-3
Total Generation Cost (R'm)	4,808	4,508	301
CO2 Emissions (Gt)	3.0	3.0	0.0

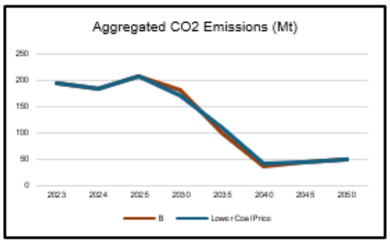
Figure 68: Sensitivity 10 Higher CCS Capex (2x)

xi. Sensitivity 11: Lower Coal Price

Question: What happens if coal prices are 60% lower than the base case? (From R45/GJ to R18/GJ)

Cheaper coal results in higher coal dispatch and lower gas dispatch. More coal plants remain online for longer, compared to Scenario B. By 2050, the capacity build and energy mix are similar to Scenario B.





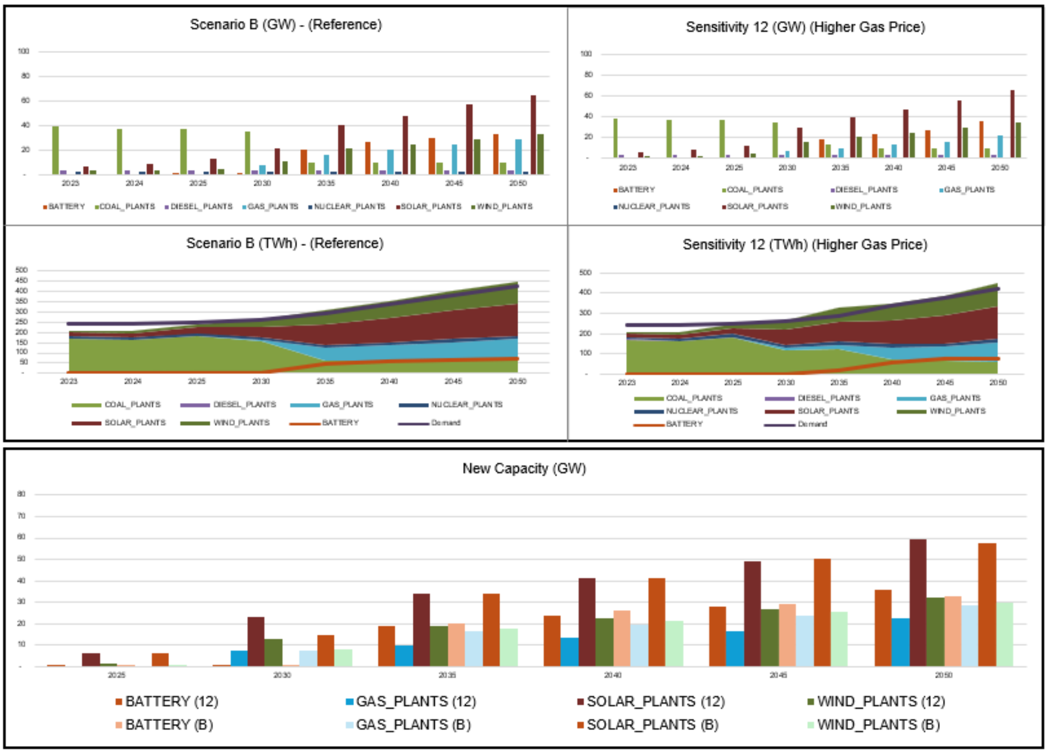
SENSITIVITY	11	B	Delta
VRE Capacity (GW)	98	97	1
BESS (GW)	33	33	0
Dispatchable Capacity (GW)	79	82	-3
Total Generation Cost (R'm)	4,541	4,508	33
CO2 Emissions (Gt)	2.9	3.0	-0.1

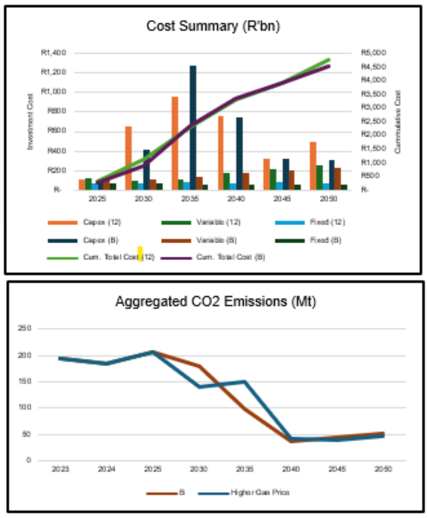
Figure 69: Sensitivity 11 Lower Coal Price

xii. Sensitivity 12: Higher Gas Price

Question: What happens if gas prices are 30% higher than the base case? (From R200/GJ to R260/GJ)

A rise in gas prices reduces gas dispatch, increases coal, renewables, and energy storage, and raises overall system costs.





SENSITIVITY	12	B	Delta
VRE Capacity (GW)	101	97	4
BESS (GW)	36	33	3
Dispatchable Capacity (GW)	79	82	-3
Total Generation Cost (R'm)	4,745	4,508	237
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 70: Sensitivity 12 Higher Gas Price

xiii. Sensitivity 13: Reduced Carbon Tax

Question: What happens if the carbon tax is increased from 104 to 68 USD/ton CO_2 in 2050?

Lower carbon taxes increase coal dispatch at the expense of gas, but overall emissions constraints still limit long-term coal contributions. Tutuka, Matimba, Lethabo, and Kendall coal plants receive AQ retrofits and remain online until 2045, without CCS retrofits. The total generation cost increases due to increased coal consumption; however, when including the carbon tax cost, Sensitivity 13 has a lower cost than Scenario B.

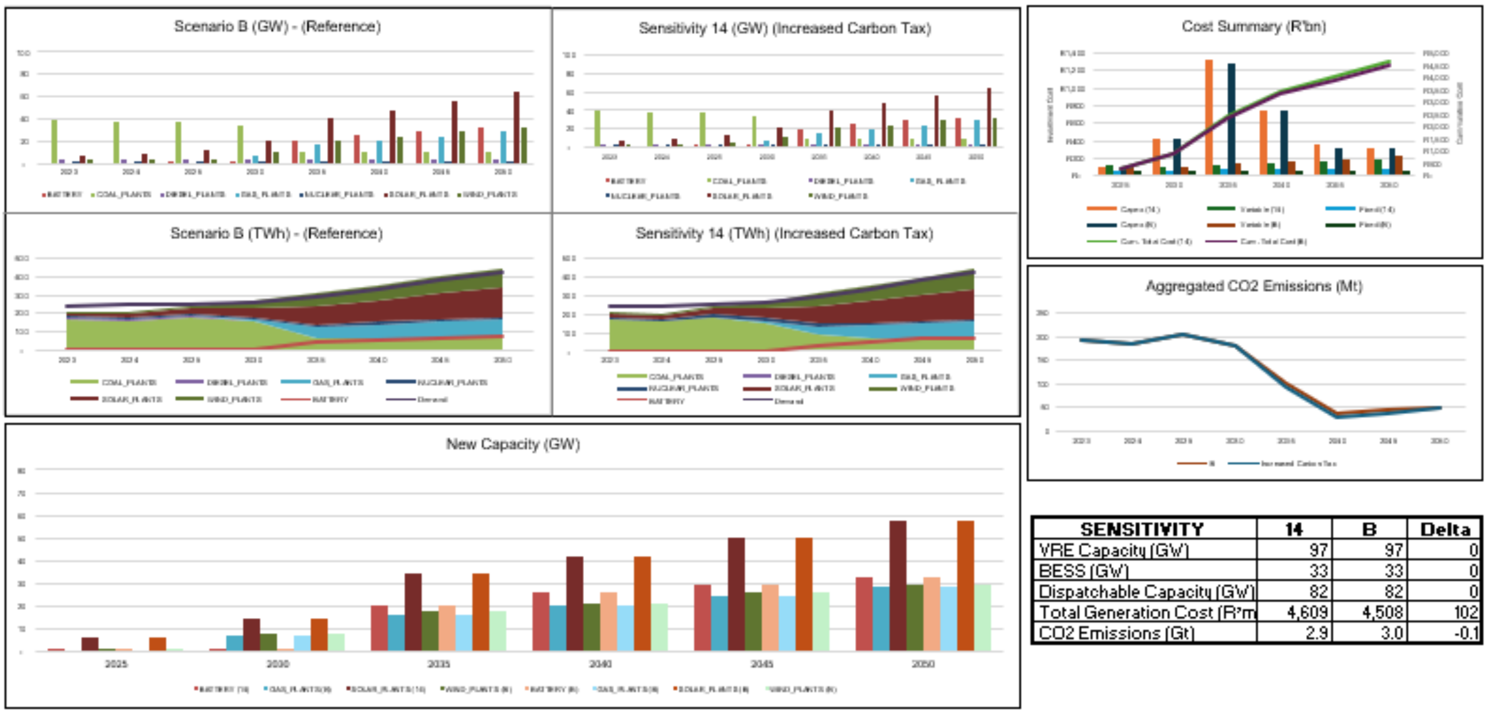
SENSITIVITY	13	B	Delta
VRE Capacity (GW)	94	97	-3
BESS (GW)	32	33	-1
Dispatchable Capacity (GW)	84	82	2
Total Generation Cost (R'bn)	4,695	4,508	187
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 71: Sensitivity 13 Reduced Carbon Tax

xiv. Sensitivity 14: Increased Carbon Tax

Question: What happens if the carbon tax is increased from 104 to 188 USD/ton CO_2 in 2050?

Higher carbon tax (which increases more substantially from 2035 to 2050) reduces gas generation in favour of renewables between 2035 and 2050. The total CO_2 emissions over the period 2025 to 2050 remains similar, indicating that the CO_2 budget is the primary constraint driving CO_2 emissions. A higher carbon tax than was modelled in this sensitivity would be required to drive CO_2 emissions below the 3.0 Gt budget from a cost perspective.



SENSITIVITY	14	B	Delta
VRE Capacity (GW)	97	97	0
BESS (GW)	33	33	0
Dispatchable Capacity (GW)	82	82	0
Total Generation Cost (R'm	4,609	4,508	102
CO2 Emissions (Gt)	2.9	3.0	-0.1

Figure 72: Sensitivity 14 Increased Carbon Tax

Annexure E: Emerging, Innovative, and Disruptive Gx and Tx Technologies

A disruptive technology is specifically one that can fundamentally change not only established technologies, but also the rules and business models of a given market, and often, business and society as a whole (Perez and Leach, 2022). The following list refers to many technologies that could be categorized as being disruptive or innovative, as well as their associated functions in the electricity industry value chain.

- **Digitalization in the energy sector:** The incorporation of digitalization in renewables, combining data, analytics, and connectivity, serves as a facilitator in developing future energy systems. New technologies should facilitate faster integration of renewable energy projects into the grid. This integration provides increased flexibility to customers, utilities, and other market participants (Johnstone et al., 2020). Technologies like the Internet of Things (IoT) and smart grids support the expansion of VRE technologies, such as solar PV and wind, by enhancing the efficiency and reliability of energy systems. Specifically, these technologies have the potential to bring about a wide range of improvements and benefits:
    - Real-time data: Smart meters provide real-time data on energy usage, allowing consumers to monitor their consumption patterns and make informed decisions to reduce their energy use and costs. This transparency promotes energy efficiency (IEA, 2023).
    - Grid stability: Grid-forming inverters can ensure frequency and voltage stability in grids with high renewable energy penetration, mimicking the inertial response of traditional generators. They also provide black start capability and fault ride-through support, ensuring grid reliability and stability (Lin et al., 2020).
    - Grid-scale energy storage: Large-scale energy storage systems, such as lithium-ion batteries and PHS, are crucial for balancing supply and demand. They stabilize the grid by storing excess energy during low-demand periods and releasing it during peak-demand periods (StartUs-Insights, 2024).
    - High-voltage direct current (HVDC) Transmission: HVDC technology facilitates efficient electricity transmission over long distances with lower losses compared to traditional AC systems. This technology is particularly useful for integrating remote renewable energy sources into the grid (FutureBridge, 2023).
    - Dynamic line rating (DLR): DLR systems use real-time data to determine the actual capacity of transmission lines based on current weather conditions and line temperatures. This enables the optimization of existing infrastructure, thereby increasing the capacity and reliability of the grid (Arusi LLC Engineering, 2023).
    - Demand response: By providing detailed consumption data, smart meters enable demand response programmes where consumers can adjust their energy usage during peak times in response to price signals or incentives from the utility. This assists in balancing the load

on the grid and reduces the need for additional power generation during peak periods (IEA, 2023).

- Enhanced billing accuracy: Smart meters provide billing based on actual rather than estimated consumption, improving billing accuracy and fairness. This should reduce disputes between consumers and suppliers, thereby improving customer satisfaction (European Commission, 2024).
- Fault detection and maintenance: Smart meters can rapidly detect outages and other energy supply issues, allowing for faster response times and improved maintenance. This improves the reliability and resilience of the energy grid (IEA, 2023).
- Customer empowerment: Consumers have direct access to their energy consumption data and can permit third parties to use this data to provide tailored energy-saving solutions. This access empowers consumers to take control of their energy usage and participate actively in the energy market (European Commission, 2022).
- Personalized services: Energy suppliers can use data analytics to offer personalized energy plans and recommendations based on individual consumption patterns. This can include suggestions for energy-saving measures or the optimal time to use energy-intensive appliances (IEA, 2023).
- Enhanced communication: Digital platforms enhance communication between suppliers and customers. For example, mobile apps and online portals allow customers to track their energy usage, pay bills, and receive notifications about outages or maintenance work (IEA, 2023).
- Load forecasting: Advanced data analytics and machine learning algorithms can predict energy demand patterns, allowing utilities to optimize their operations and reduce costs. Accurate load forecasting helps to ensure a stable and reliable energy supply (IEA, 2023).
- Integration of renewable energy: Smart grids, enabled by digital technologies, can improve the integration of VRE sources like solar and wind. By matching supply with demand in real time, smart grids enhance the efficiency and reliability of renewable energy systems (IEA, 2023).
- Energy storage management: Digital tools can optimise the use of energy storage systems, ensuring that excess energy generated during low-demand periods is stored and used during peak demand times. This helps to balance the grid and reduce reliance on fossil fuels (IEA, 2023).

- **Grid curtailment and weather forecasting:** This refers to the intentional reduction of renewable energy output to maintain grid stability when supply exceeds demand or due to transmission constraints. Accurate weather forecasting is essential for 'day-ahead' predictions of renewable energy generation and managing curtailment effectively (World Climate Service, 2024). Advanced forecasting solutions, such as those using AI and high-resolution models, enable utilities to anticipate periods of high renewable generation and adjust grid operations accordingly. This reduces curtailment losses, optimises energy storage, and ensures a stable and reliable energy supply (Climavision, 2025). Specifically in the South African context, grid curtailment can be used to increase the integration of wind generation capacity within constrained grid areas. This mechanism increases the usage of the transmission grid (capacity factor), thereby facilitating energy flow through the limited grid capacity to the load. Weather forecasting allows for improved planning, prediction, and associated dispatch of the flexible technologies, thus facilitating higher integration of VRE into South Africa's energy grid at any time.

While some technologies are currently still emerging in new regions, they can potentially be considered disruptive. Emerging technologies are innovations that are still in development or in the early stages of adoption, such as advanced nuclear reactors and AI-driven energy management systems. They promise significant improvements but require further refinement and scaling. In contrast, disruptive technologies fundamentally alter existing markets and practices. Examples of disruptive technologies include solar PV and battery storage, which have drastically reduced reliance on fossil fuels. These technologies often face initial resistance but eventually reshape industries (Capgemini, 2025).

Table 51 provides a summary of the maturity levels and applicability of innovative renewable energy generation technologies in the South African context by 2050.

Table 51: Innovative Renewable Energy Generation Technologies By 2050

Technology	Disruption Potential	Maturity	Expected Full Deployment	Applicability to South Africa
Small Modular Reactors (SMRs)	Moderate	Developing	2040–2050	High, with various government spheres announcing interest (Engineering News, 2025; World Nuclear News, 2024).
Offshore Wind	Very High	Developing	2030–2040	Moderate, with potential in coastal areas but higher costs and technical challenges (Hutt, 2022).
Long-Duration Energy Storage (LDES) (e.g., flow batteries)	Very High	Emerging	2030–2040	High potential to support grid stability and renewable integration (McKinsey & Company, 2024).
Ocean Energy (Tidal and Wave)	Low	Preliminary stages	2040–2050	Low, due to limited coastal infrastructure and higher costs (IRENA, 2020).
Solar Photovoltaic (Solar PV)	Very High	Fully developed	Ongoing	Very high due to abundant sunlight and decreasing costs

Technology	Disruption Potential	Maturity	Expected Full Deployment	Applicability to South Africa
				(IEA, 2023; McKinsey & Company, 2024).
Floating photovoltaic (FPV)	High	Emerging	Ongoing	High potential due to numerous water bodies, such as reservoirs or dams (Zero Point Energy, 2020)
Concentrated Solar Power (CSP)	Moderate	Developing	2030–2040	High potential in sunny regions, but higher costs compared to PV (IRENA, 2020).
Onshore Wind	Very High	Fully developed	Ongoing	High potential, especially in coastal and inland regions with strong wind resources (McKinsey & Company, 2024; IRENA, 2020).
Geothermal	Low	Developing	2030–2040	Limited by geographic availability in South Africa but potential in certain regions (IRENA, 2020).
Bioenergy	Moderate	Fully developed	Ongoing	Regionally variable, with potential in agricultural and forestry sectors (IRENA, 2020).
Hydropower	Moderate	Fully developed	Ongoing	Limited due to environmental concerns and site availability (IRENA, 2020).

Annexure F: Mapping of Research Questions to Report Sections

Table 52: Research Questions Mapped to Report Sections

	Question	4 Infrastructure Technical Modelling	4.5 Sensitivity Analyses	5 Market Sounding the Energy Infrastructure Funding Gap	6 Estimating the Energy Infrastructure Funding Gap	7 Policy and Regulatory Review
1	Given the probable impacts of climate change on the global commitment to decarbonization over the coming decades, what should the financing targets be to achieve the energy and carbon SDGs and NDP goals by 2030, and extended to 2040 and 2050?	x	x			
2	What is the funding gap between current levels of investment in energy infrastructure and what will be required to achieve the relevant energy and carbon SDGs, NDP, NDC goals, covering new capital, operations, and maintenance spending?			x	x	
3	What policy and regulatory frameworks are in place that govern the flow of public and private investments in energy infrastructure and service delivery with respect to technologies, service levels, and resilience in the face of climate change?					x
4	What policy, institutional, and regulatory (PIR) changes will be required to increase investment in climate-resilient energy infrastructure and services, and achieve the NDP and SDG targets?			x		x
5	What are the barriers to achieving SDG 7.1 (universal access to affordable, reliable, sustainable, and modern energy services) and the associated NDP goals, and what needs to be addressed?	x	x			x

6	How can the reliability of power supply, which disproportionately affects poorer households, be improved to meet SDG targets and NDP objectives, while being aligned to the Just Transition Framework (JTF)?	x	x	x		
7	Is there a trade-off between the SDG 7 targets, NDP targets, sectoral targets, and the NDC commitments, and if so, what are they?	x	x			
8	What will be the expected contribution of the existing IRP 2019 to SDG 7.2?	x	x			
9	What would be the expected contribution of investment in transmission, according to the Eskom TDP, in terms of supporting SDG 7?	x	x			
10	What would be the expected contribution of disruptive innovations on SDG 7.2 and SDG 7.3?	x	x	x		x
11	What would be a cost-effective path to achieve SDG 7.1 based on existing service standards?	x	x			

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