South Africa's Energy Sector Investment Requirements to Achieve Energy Security and Net-Zero by 2050

20 June 2025

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Executive Summary

Purpose and Scope

The Development Bank of Southern Africa (DBSA), Presidential Climate Commission (PCC), the National Planning Commission (NPC), 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 Engineering Group (OEG) to assess the energy infrastructure investments required between 2024 and 2030 (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), and National Infrastructure Plan (NIP) 2050 ambitions in the energy sector, as well as the United Nations Sustainable Development Goals (SDGs) – specifically pertaining to SDG 7 (‘affordable and clean energy’). The objectives of this study therefore 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 above-mentioned outcomes.

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

In addition, the project team also 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 funding gap estimate, and completed a Policy, Institutional, and Regulatory (PIR) analysis related to the energy financing landscape. Additionally, a socio-economic

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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, LNG terminals, petrochemicals manufacturing, coal mines, etc.

[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.

impact modelling study, using the scenario output from this study's technical modelling, has been completed and will be published in a supplemental report.

This work will feed into the broader SA-TIED workstream 5 related to Water-Energy-Food (WEF) in the context of Climate Change (WEF CC) with a particular focus on the WEF nexus. The study does not address WEF nexus issues, but it forms part of the groundwork for the ongoing work on this topic.

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 broken down 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. 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 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 line with South Africa's NDC targets.
        - As per SDG 7.2, increase substantially the share of renewable energy in the global energy mix 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 stated a goal to 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, as well as overall stepping up of investments in energy-efficiency (RSA, 2021).
- **Identify metrics to** monitor **infrastructure services:** The metrics to monitor relate to South Africa's NDC targets and performance against SDG 7 targets and its 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, 2023).

  - **The contribution of renewable energy to the country's total energy portfolio:** In 2021, this figure stood at 9.7% (United Nations Statistics Division, 2023).
  - **Energy efficiency:** In 2021 (the latest available data) the ratio between energy supply and economic output was 6.6 megajoules per constant 2017 purchasing power parity GDP (MJ/USD 2017 PPP GDP) (United Nations Statistics Division, 2023).
  - **Energy Availability Factor (EAF):** For the 2024 calendar year, South Africa's EAF averaged 59.8% (Eskom, 2025)
  - **Affordability of technology options:** This metric will be expressed as a per annum cost for capital and operational expenditure in 2024 real terms, comparable across the various scenarios.
  - **Annual carbon emissions (CO_2e):** South Africa's 2022 (the latest available data) emissions, were estimated at 436 $MtCO_2e$ (DFFE, 2024), which is above the 350-420 $MtCO_2e$ target range.

- **Identify the types of options available:** For the purposes of this study, three energy scenarios (including sensitivity testing) were developed considering the following considerations:
  - **Pathway / scenario-specific inputs and assumptions**
    - Policy and regulations: 1) Carbon emissions from electricity, 2) Adherence to air quality standards, 3) Carbon Border Adjustment Mechanism (CBAM) and other export market regulations, and 4) Carbon emissions tax (CO_2 tax)
    - Generation: 1) Coal fleet decommissioning schedule, 2) EAF, 3) Carbon Capture Storage (CCS) viability timeline, and 4) Technology learning rates
    - Fuel prices
    - Capital: 1) Size of the market / 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 & generation build rate, and 5) Technology options (including load shedding / unserved energy)
    - Demand: 1) Universal access to electricity, 2) Demand and energy forecasts per sector, 3) Fuel switching, and 4) EVs
    - Regional electricity trade (via the Southern Africa Power Pool (SAPP))

- **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 funding into South Africa's electricity infrastructure. Along with determining the options that are available, these exogenous factors influenced the determination of the range of the South African carbon budget to 2050.

- **Estimate costs of achieving objectives:** This step was completed in two broad ways. Firstly, extensive energy (electricity generation) and power systems (grid stability) (holistically termed "technical") modelling were conducted and informed by technical consultation sessions to obtain among others, new capacity build programme, energy mix, and total capital expenditure (Capex) estimations. The results were compared to the ranges that were identified in the parallel literature review study. In addition, a supplementary Computable General Equilibrium (CGE) modelling report will be produced to provide insight on the socio-economic impact stemming from the pathways / 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. A range of funding options and their respective mobilisation requirements (i.e., financial, policy, institutional, regulatory, or technical) were considered that could fill the remaining funding gap. 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 were conducted. PIR changes that will be required 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, envisaged a spectrum of local and international pathways which provide the overarching conditions and limitations under which the associated scenarios must be modelled. While informed by a wide range of data and information, these pathways are based on South Africa's JET Investment Plan (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, which was presented to the UNFCCC (2022) (DFFE: SA-LEDS, 2020).

The international development pathways are:

- A **global alignment** to keep global warming to below 1.5 degrees Celsius in relation to pre-industrial levels as per the Paris Agreement.
- A **fragmented** world where only certain countries achieve their NDC targets and warming is limited to below 3 degrees Celsius.
- A **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 Industrialisation** 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 mandated air quality compliance by 2030. Under this pathway, a large market exists for GI finance, and cost of capital is low and accessible for renewable energy technologies, while cost of capital for fossil fuel technologies attracts a premium. Also, new technology learning rates are optimistic (i.e., costs reduce), competition for fossil fuels is low (which results in lower coal and gas prices), and the EAF of the existing coal fleet improves.
- The **Market Forces** pathway assumes that the country is generally aligned to its NDC targets, but that 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 remain within the strict adherences to air quality standards and carbon policies. Under this pathway, a carbon emissions limit of 3 Gt by 2050 is assumed for the electricity sector and air quality 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 and / or acute economic cost challenges) and a focus on electricity production through least cost and 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 which relate to the conditions under these pathways:

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

Results and Findings

Operating capacity

The infrastructure technical modelling identified the energy mix with the lowest investment requirement to meet the national electricity demand, based on the 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 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, also 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 2030 and 2050 per Scenario (GW)

Year	Technology	Scenario A (Green Industrialisation)	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

Year	Tech-nology	Scenario A (Green Industrialisation)	Scenario B (Market Forces)	Scenario C (Business-as-usual)
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.

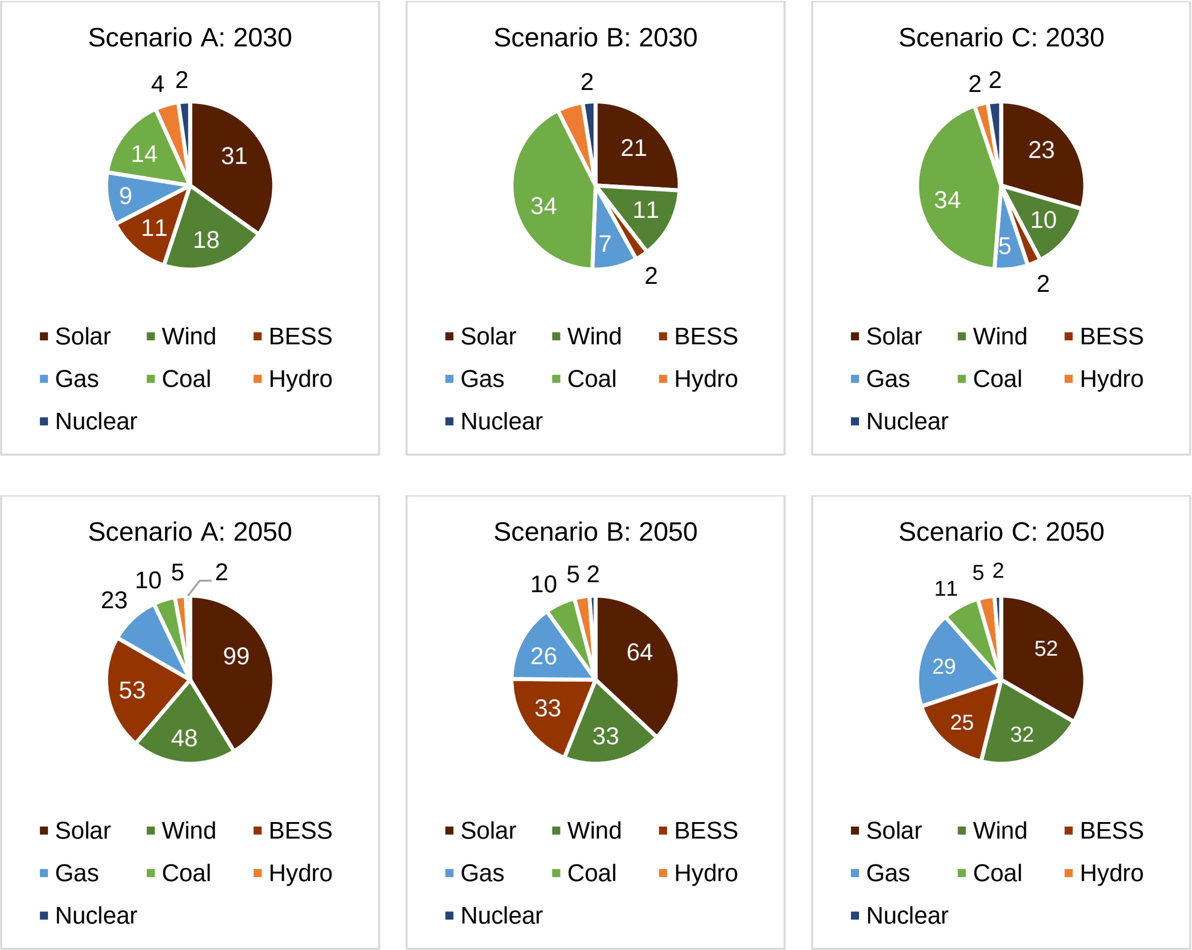

Figure 1: Operating Capacity per Technology in 2030 and 2050 per Scenario (GW)

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 Northern Cape to Gauteng via North West and Hydra Central to Gauteng via 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 would likely result in a partial exceedance of 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 because this is not possible by focussing only on the electricity sector.

The resultant CO_2 emissions per scenario for the period from 2023 up to 2050 is shown in Figure 2. Scenario A achieves 123 Mt/a CO_2 emissions in 2030, which is generally considered to be 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).

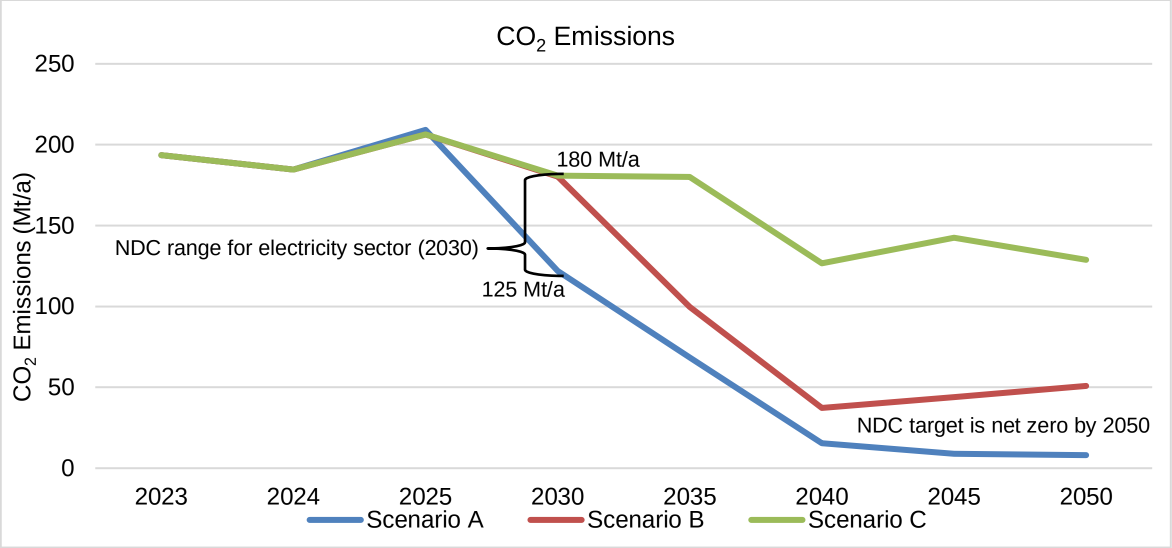

Figure 2: CO_2 Emissions per Scenario

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

Table 2: Total Investment Requirement per Scenario from 2025 to 2050 (R billions, Discounted at 8% to 2024)

Investment detail	Scenario A (Green Industrialisation)	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

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[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)*

Scenario A requires the highest average annual investment in the period 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. Following this, Scenario A benefits from the lower variable generation costs, and requires the lowest average annual investment for the period 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 there will be a significant funding gap over the longer term.
- **Pricing as a limitation to financing of renewable energy infrastructure:** pricing is a significant barrier / limitation 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 uncertainty and unpredictability of policies and frameworks related to transmission and distribution infrastructure which is, in turn, seen as 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 transmission energy infrastructure.
- **Role of credit enhancements for financing energy infrastructure in South Africa:** local commercial banks indicated that credit enhancements play a moderate role, whilst pension funds and IPPs have indicated that the role of credit enhancements are important for 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-to-no appetite to take 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 / 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; Income Tax Act 58 of 1962, as amended (ITA), Section 23M limitation on the deductibility of interest on debt; a lack of clarity for transmission energy 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:** Despite approximately R 118 billion in annual available private finance and an overall (i.e., including the IPG loan and public sector funding) annual R 127.6 billion during 2025 to 2027, the estimations suggest that there could still be a significant annual Capex funding gap (including grid costs) during this first period for Scenario A (Green industrialisation) and, to a lesser extent, for Scenario C (Business-as-usual). During the periods 2028 to 2030 and 2031 to 2050, as a low and high private funding attraction alternative (i.e., the ability of the market to attract private investment into energy infrastructure compared to the first period’s estimated available finance value of R 118 billion) is introduced, the funding gaps increase across all scenarios under the prevailing Capex outlays.

- **Scenario Results:** 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 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, Scenario B (Market Forces) shows the lowest overall Capex funding gap range (R 76.7 to R 88.5 billion) while Scenario C (Business-as-usual) shows the highest (R 110.3 to R 122.1 billion), with Scenario A’s (Green industrialisation) range falling in between (R 95.5 to R 107.3 billion). From 2025 to 2030, the annual average Capex outlay for Scenario A (Green industrialisation) is much higher than for Scenario C or Scenario B, which could potentially challenge the country’s ability to secure these levels of funding in the short- to medium-term.

Table 3: Capex Funding Gap per Scenario and (Private) Funding Attraction Alternatives[4] (R' billions p.a., 2024 Prices and % of GDP)

Scenario	**Scenario A (Green industrialisation)**		**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	99.1 (1.35%)		-17.4 (-0.24%)		13.9 (0.19%)	
2028 – 2030	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**
Capex gap	140.0 (1.91%)	130.6 (1.78%)	23.6 (0.32%)	14.1 (0.19%)	54.9 (0.75%)	45.4 (0.62%)
2031 – 2050	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**
Capex gap	107.3 (1.46%)	95.5 (1.30%)	88.5 (1.21%)	76.7 (1.05%)	122.1 (1.67%)	110.3 (1.51%)

- **Including Opex:** By including Opex in this equation, the gap increases from between 2.21% and 3.55% of GDP during the period from 2025 to 2027, to between 3.09% and 5.28% during the period from 2031 to 2050. Importantly, this does mean that Scenario A becomes the most affordable option over the full period due to its Opex being much lower than the other two scenarios.

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 like the White Paper on Energy Policy of 1998 and the Draft South African Renewable Energy Masterplan (March 2022) outline strategic objectives but face challenges in formalising funding mechanisms.
- The National Integrated Energy Plan, 2016 *(GN No. 40445 of 25 November 2016)* and Electricity Regulation Amendment Act 38 of 2024 *(GG No. 51100 of 20 August 2024)* propose decentralisation and modernisation 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.

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[4] *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.*

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 Industrialisation) assumes optimistic technology learning rates, lower fuel prices, higher carbon tax, and a strong alignment with both local and global green industrialisation 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 R 1 651 billion for generation; lowest operation, maintenance and fuel investment of R 1 552 billion; highest grid capacity investment of R 383 billion; but the lowest total system investment of R 3 586 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 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 R 1 229 billion; R 2 166 billion for operations, maintenance and fuel; and R 262 billion for grid expansion, with a total system investment of R 3 657 billion – 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 – 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 industrialisation. 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 R 1 446 billion for generation Capex investment; R 2 490 billion for operations, maintenance and fuel – highest; and R 231 billion for grid Capex – lowest; resulting in the highest total system investment of R 4 166 billion – 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 – 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.

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

New Generation Capacity: In all scenarios, the largest component of new generation capacity consists of variable renewable energy (VRE) technologies, such as solar PV and wind, supported by new battery energy storage systems (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. 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 diminishing private sector funding in the medium and 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.
- **Closing the Funding Gap:** The funding gap will have to be sourced from private sector and donor sources.
- **Tariff Setting and Collections:** While the tariff setting process includes various considerations, 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 prioritising 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, though total system investment required is higher. However, broader climate risks may still favour policies aligned with Scenario A.	Minister of Electricity and Energy	
1.3 Scenario C: While Scenario C prioritises least-cost electricity supply under 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 duration support. Establish / 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.	DOE	
1.7 Air Quality (AQ) retrofits only for plants with longer remaining life: Decommission coal plants with shorter remaining life instead of deploying AQ retrofits. Conduct thorough cost-benefit analysis before investing in AQ retrofits.	Eskom (Generation)	
1.8 Investigate and monitor feasibility of carbon capture and storage (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 Decentralised energy systems: Implement renewable energy-based microgrid systems for rural communities to improve quality of life and create job opportunities.	DOE	NECOM
1.11 Co-locate RE generation infrastructure with demand: Reduce transmission losses and improve energy efficiency by co-locating RE infrastructure with demand centres like industrial parks and urban areas.	NTCSA	IDC
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:	DOE, NTCSA (Market Operator)	

2.1 Debt funding instruments / products need to be **repriced** to ensure liquidity and long-term participation from the secondary market given sector exposure limits etc. from local commercial banks.	Commercial Banks, Development Banks	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.	IPPO, DOE	
2.3 National Treasury backed guarantees or similar guarantee type vehicles such as a World Bank Guarantees Program with an 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.	NT	
2.4 From a market risk perspective, the development of a **wholesale energy market** should be finalised to create liquidity and pricing certainty which 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** 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**.	DOE	NTCSA
2.7 Reindustrialisation and capacitation of **technical skills** to support the energy infrastructure construction market, as well as for engineering, procurement, and construction (EPC) contractors.	DTIC, IDC	
2.8 Improved coordination of various public stakeholders to ensure projects can progress to bankability and implementation.	COGTA	
2.9 Promotion and education of pension funds relating to alternative assets 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, swops 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 distribution energy infrastructure framework could attract additional funding from potential funders for energy generation and distribution infrastructure as it will open and grow the energy market.	COGTA, NT	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 EEG, 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.	NT	DOE
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.	NT	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 (RECs) for compliance and incentivise investments through supportive legislation.	NT, DOE	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:	Eskom (Distribution)	NTCSA

• **Reduced Conflict of Interest:** Separate the GAU from Eskom Distribution to minimise 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 • **Enhanced Collaboration:** Direct access to resources and authority improves coordination and the progression of technical designs and user requirements for grid connections.		

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Acknowledgements

The preparation of this report was led by Dirk Mostert (PwC), Andrew Johnson (OEG), and Derek Verrier (DBSA). Mark Swilling (NPC and SA-TIED) played a key role in putting this partnership effort in motion and provided regular input to the project team. Dipak Patel (PCC), Steve Nicholls (PCC), Georgina Ryan (NT and SA-TIED) and Zeph Nhleko (DBSA) provided technical guidance throughout the process.

The PwC team comprised Albie Alant, Heinrich Bohlmann (UP), Kyle Drury, Michelle Georgiou, Niel Gerryts, Nathan Herrick, Vicky Hibbers, Lullu Krugel, Khalid Mather, Dirk Mostert, Portia Moutlwatsi, Rowyn Naidoo, Salome Ntsibande, Roelof van Huyssteen, and Christie Viljoen.

The OEG team comprised Andrew Johnson, Sechaba Malahleha, Rabagolo Melesi, Michael Reed, and Dumisani Sebanda.

The Project Steering Committee was chaired by Sampson Mamphweli (SANEDI). The DBSA team comprised Adel Bosch, Zeph Nhleko, and Derek Verrier. The NPC team comprised Puleng Molokwane and Mark Swilling. The NT / SA-TIED comprised Aalia Cassim, Georgina Ryan, and Mark Swilling. The PCC team comprised Steve Nicholls, and Dipak Patel.

The team thanks for comments, guidance, and support Tokologo Bathupetsane (SUN CST), Ronald Marais (NTCSA), Antoine Godin (AFD), Paul Hadjilazaro (AFD), Ntumba Katabua (AFD), Matema Modiba (DPME), Lydia Maredi (DPME), and Harro von Blottnitz (UCT ESRG).

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 Dates
COGTA	Department of Cooperative Governance & 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

DOE	Department of 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
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
EVs	Electric Vehicles
FGD	Flue Gas Desulphurisation
FiTs	Feed-In Tariffs
FOM	Fixed Operation and Maintenance
GAU	Grid Access Unit
GCCA	Generation Connection Capacity Assessment
GDP	Gross Domestic Product
GEMPACK	General Equilibrium Modelling Package
GHG	Greenhouse Gas

GI	Green Industrialisation
GIS	Geographic Information System
GIPPPP	Gas Independent Power Producer Procurement Programme
Gt	Giga tons
$GtCO_2e$	Giga tons of carbon equivalent
GW	Gigawatt
GWh / GW/h	Gigawatt hour
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
ITA	Income Tax Act
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
IPCC	Intergovernmental Panel on Climate Change
kWh	Kilowatt-Hour
KZN	Kwazulu-Natal
LEAP	Low Emissions Analysis Platform
MES	Minimum Emission Standards
MoManI	Model Management Infrastructure
Mt	Megatons
$MtCO_2$	Metric Tons of Carbon Dioxide
$MtCO_2e$	Metric Tons of Carbon Dioxide Equivalent
MtPA	Megatonne per annum
MW	Megawatt
MW/h, MWh	Megawatt hour
NECOM	National Energy Crisis Committee
NBI	National Business Initiative
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	Nonprofit Organisations
NREL	National Renewable Energy Laboratory
NSP	Network Service Provider
NTCSA	National Transmission Company South Africa Soc Ltd
NT	National Treasury

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	Photovoltaics
RECs	Renewable Energy Certificates
REIPPP	Renewable Energy Independent Power Producers Programme
REIT	Real Estate Investment Trust
RES	Reference Energy System
RFP	Request for Proposal
ROC	Renewables Obligation Certificates
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 Goals
SOE	State-Owned Enterprise
SPP	Strategic Partnership Programme
SSEG	Small-scale embedded generation
StatsSA	Statistics South Africa
STEPS	Stated Policies Scenario
SUN	Stellenbosch University
TDP	Transmission Development Plan
ToR	Terms of Reference
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
WEF	Water-Energy-Food
WEO	World Energy Outlook
WEF CC	Water-Energy-Food in the context of Climate Change
WHO	World Health Organisation

Section A: Introduction, Approach and Pathways Development

1 Introduction

In 2012, the National Development Plan (NDP) was promulgated to outline goals that are to be achieved by various sectors in South Africa by 2030, including energy and infrastructure towards alleviating load shedding and spurring economic activity (RSA, 2012). In 2015, all United Nations member countries adopted the 2030 Agenda for Sustainable Development, which sets out 17 goals, 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 Convention on Climate Change (UNFCCC) are parties to the Paris Agreement. Included in the Paris Agreement is the Nationally Determined Contributions (NDCs) which represent each member state's commitment towards mitigating national emissions and the adaptation efforts towards climate change.

A partnership between the Development Bank of Southern Africa (DBSA), Presidential Climate Commission (PCC), the National Planning Commission (NPC), and National Treasury via its programme Southern Africa - Towards Inclusive Economic Development (SA-TIED), was formed to assess the level of investment required between 2024 and 2030, and onwards to 2050, to achieve the Sustainable Development Goals (SDGs), NDP commitments and National Infrastructure Plan (NIP) 2050 ambitions in the energy sector, while navigating the NDC emissions window that South Africa has pledged to ratify under 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[5] infrastructure and power systems (technical) modelling, soft market sounding, funding gap estimation, and regulatory review. This report is supported by a literature review to inform the analysis and allow for results comparison. 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 / scenarios generated in this report.

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[5] *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, coal mines, etc.*

This work will also form part of the broader SA-TIED workstream 5 related to Water-Energy-Food (WEF) in the context of Climate Change (WEF CC) with a particular focus on the WEF nexus. The study does not address WEF nexus issues, but it forms part of the groundwork for the ongoing work on this topic.

1.1 The South African Electricity Governance and Operational Structure

The South African electricity landscape is dominated by Eskom Holdings SOC Ltd (Eskom), the state-owned utility. The SA Energy White Paper finalised 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, meaning a prolonged period of the electricity supply industry remaining as it was, while most other countries progressed on their liberalisation journey.

Government has more recently embarked on a process to unbundle the vertically integrated Eskom into three wholly owned subsidiaries: generation, transmission, and distribution under 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 expected to be that the transmission entity can be ring-fenced to facilitate new generation investment.

There are processes underway towards achieving this change in the structure of the electricity supply industry in South Africa. The first is the unbundling of Eskom in line with the Roadmap for Eskom - released in October 2019 by the Department of Public Enterprises (DPE) - in a Reformed Electricity Supply Industry (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), where NTCSA is a juristic person and a state-owned company that is wholly owned by Eskom. The NTCSA Transmission licence application includes the following services as 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 is seen as a step towards the unbundling of Eskom and could open the way for a competitive energy generation sector, where multiple electricity producers sell to the national grid, and various private customers.

The details of the ultimate vision for the future energy market and the end state of the industry, and the implication on current stakeholders, is still unclear. A comprehensive and agreed framework is not yet visible and there appears to be conflicting understanding of the market requirements. The role of the NTCSA as it performs the traditionally independent function in reformed markets, is set out in the Amendment Bill to include:

- Grid owner / operator of physical asset.
- System Operator (National Control, etc.).
- Market Operator – the enabler for 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. The question also needs to be addressed as to what type of wholesale market-driven power sector as desired end state is most suitable, and whether there is an argument to be made for a hybrid system given South Africa's unique circumstance as the process of transition unfolds. At this stage, changes to legislation do not offer a view as to the intended end state of the retail part of the market.

1.2 The South African Electricity Infrastructure Contextual Overview

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, that is: 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 the figure below, coal dominates South Africa's energy mix with about 80% of electricity being generated via coal-fired power stations. These stations are mostly 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 about 45% of all end-users in South Africa, while the other 55% is resold by redistributors (including municipalities) (Fitch Solutions, 2024).

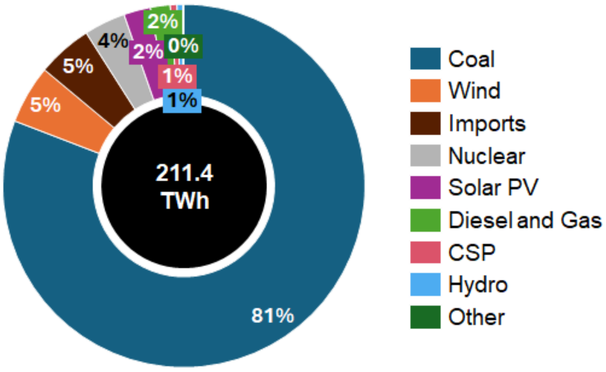

Figure 3: South Africa's Annual Energy Mix

Source: Centre for Renewable and Sustainable Energy, 2024

South Africa's reliance on coal to provide baseload energy is an artifact of the nation's mineral-energy complex industrialisation strategy, which in the past served to develop South Africa into one of the leading economic powerhouses on the continent. However, the demand for reliable and affordable energy, the nation's ageing coal-fired power-station fleet, and Eskom's weak financial position, have resulted in the South African energy sector being severely constrained.

The degradation of Eskom's coal fleet is evident via the annual average energy availability factor (EAF). Eskom's EAF has been historically on a linear decline of an average 3.8% since 2018 until January 2023 (Eskom, 2024a). The Eskom fleet EAF continued a declining trend in 2022, with an average EAF of 58.1%, compared to the EAF of 61.7% for 2021 and 65% for 2020. On the back of significant planned maintenance at the end of 2023 and beginning 2024, as well as 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 scenario with the EAF between 50% and 52% and a high scenario of between 65% and 69%.

The supply and demand imbalance in South Africa's single buyer energy model has led to loadshedding, the practice of rationing energy across the grid to prevent a demand-driven nationwide blackout continuing during 2023, where loadshedding reached its highest levels. While 2024 showed much improvement, the country experienced around 335 days of load shedding in 2023, with an estimated negative economic impact of approximately R 230 billion (Loewald, 2023). To meet the energy needs of a transformed energy landscape in step with the objectives of Eskom's coal plant decommissioning schedule, the Just Energy Transition Investment Plan (JET-IP) proposes that 50 Gigawatts (GW) of new renewable energy capacity needs to be added to the grid over the next 22 years in line with the decommissioning schedule. However, to achieve the lower end of the NDC target range of reduced emissions, 50 GW of

RE capacity should be brought online by the end of 2030 (The Presidency, 2022). The now outdated IRP 2019 – published by the Department of Mineral Resources and Energy (DMRE) - 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 (DMRE, 2019).

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

Climate change is currently altering South African ecosystems, economies, and livelihoods. According to the Department of Forestry, Fisheries and The Environment (DFFE), climate change has led to extreme weather events such as drought, floods, and rainfall fluctuations in the country, impacting the economy, infrastructure project development, and the lives of many citizens (DFFE, 2022).

The combination of reduced VRE (and storage) technology prices and households / companies looking to overcome load shedding has contributed to South Africa's decarbonisation 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 realised 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 NDCs

South Africa's Climate Change Act was promulgated in July 2024. This legislation sets out the country's national climate change response, including mitigation and adaptation actions. Further, it details South Africa's contribution to the global climate change response, encapsulated in its NDCs.

Box 1: South Africa's NDCs

NDC commitments

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 through SDG 7 and NDP (Chapter 5)

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 emissions budget over the period 2021 to 2050 of 7.8 - 8.5 $GtCO_2e$.

However, decommissioning 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, the indirect jobs associated with the coal value chain, which includes mining, beneficiation and generation, and those induced from the knock-on effects of these activities, mean 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 entirely (PwC, 2021).

National Treasury (2023) estimates that load-shedding reduced real Gross Domestic Product (GDP) growth by up to two percentage points in 2022. Despite the challenges, South Africa must aim to ensure an energy transition that achieves energy security at least cost, i.e., that is affordable.

Box 2: Specific SDGs and NDP (Chapter 5) Objectives

The SDGs are a set of 17 global goals adopted by the United Nations in 2015 as part of the 2030 Agenda for Sustainable Development. These goals were set up to address various social, economic, and environmental challenges facing the world and to guide global efforts toward a more sustainable, equitable, and prosperous future for all. The NDP 2030 is a comprehensive long-term vision and strategy aimed at addressing various socio-economic challenges within South Africa. It was introduced by the country's government in 2012 and spans an 18-year period, 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 are "outcome targets", while the last two are "means of achieving 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.
- **SDG 7.a:** 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 industrialisation and economic transformation.
- **SDG 7.b:** 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, 2025). 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 overall stepping up investments in energy-efficiency (RSA, 2012).

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

As stated in the JET-IP, the electricity technology mix to be considered 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 instruments to unlock private sector funding. Mechanisms, such as contracts for difference (CfD)[6], or price subsidies (to bridge the affordability gap), and grant funding (to de-risk early-stage pilots), need to be sourced.

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

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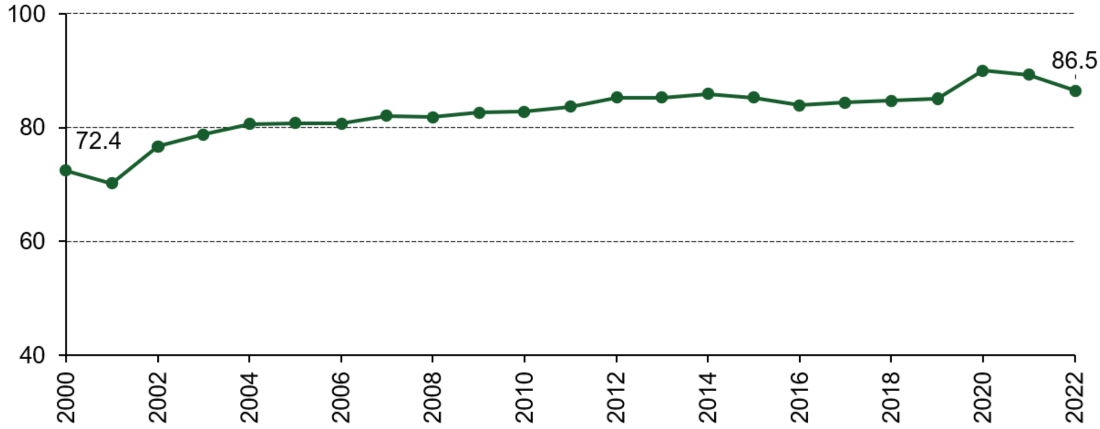
[6] *Financial agreements where the buyer and seller exchange the difference between the value of an asset at a specific future date and its value at the time the contract was initiated (meaning, if the current price is higher, the buyer gets paid the difference; if the current price is lower, the buyer 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 3: South Africa's Performance on SDG 7-related Indicators

The SDGs set out 17 overarching goals which address economic, environmental, and social impacts, and are designed to form a blueprint for good growth, nationally and internationally, by 2030. SDG 7 sets out specific goals related to affordable and clean energy, specifically to ensure access to affordable, reliable, sustainable, and modern energy for all. Below are these goals with the latest available data on South Africa's performance on them.

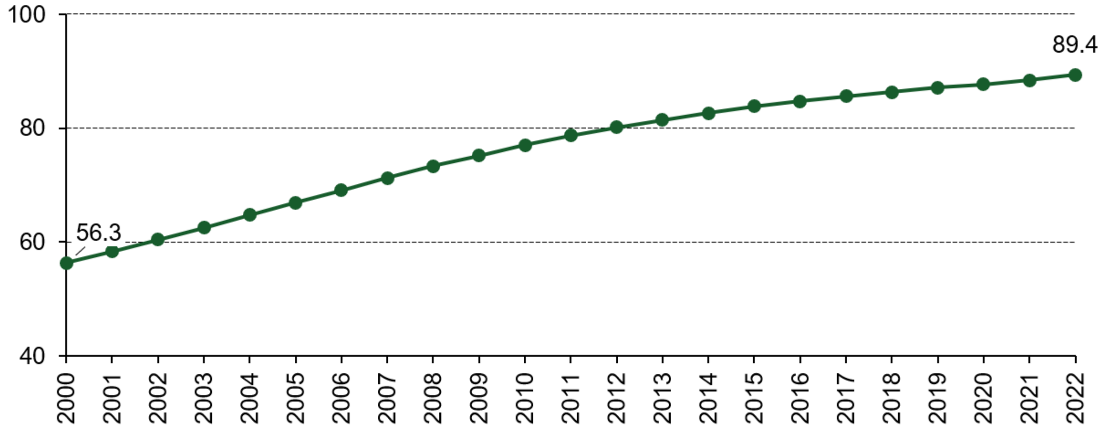
Proportion of population with access to electricity: Against the goal of universal access electricity to all South Africans by 2030, the share of current citizens with access to grid power increased from 72.4% in 2000 to 86.5% in 2022 (United Nations Statistics Division, 2023). Over this period, the Government's endeavours to expand the delivery of basic services to the growing population included expanding the provision of electricity supply to formal and informal households.

Proportion of population with access to electricity (%) – South Africa.
(United Nations Statistics Division, 2023)



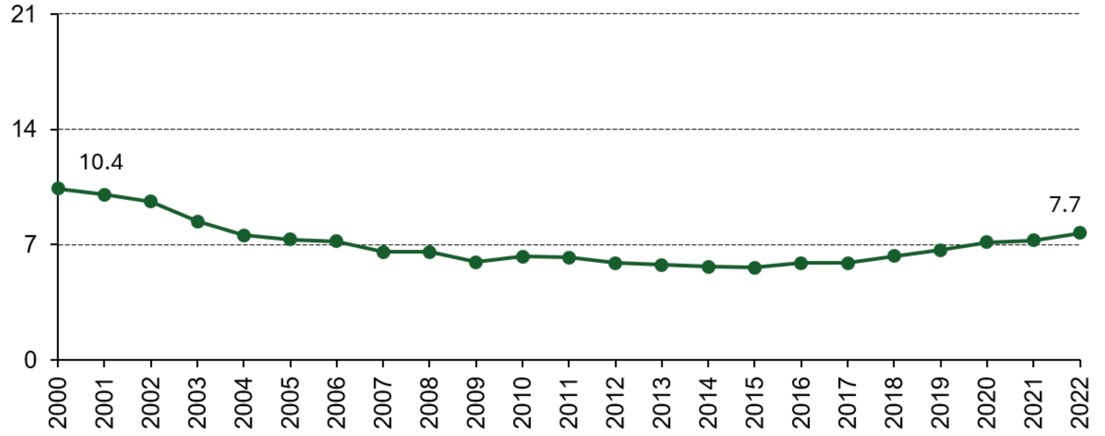
- **Proportion of population with access to clean fuels and technologies for cooking**: The share of South Africans using clean fuels and technologies for cooking, heating, and lighting increased from 56.3% in 2000 to 89.4% in 2022 (United Nations Statistics Division, 2023). In this case, "clean" is defined by emission rate targets and specific fuel recommendations (i.e., against unprocessed coal and kerosene) included in World Health Organisation (WHO) guidelines. The increase in the country's overall electrification rate has played a significant role in the progress made on this indicator.

Access to clean fuels and technologies for cooking (%) – South Africa (United Nations Statistics Division, 2023)

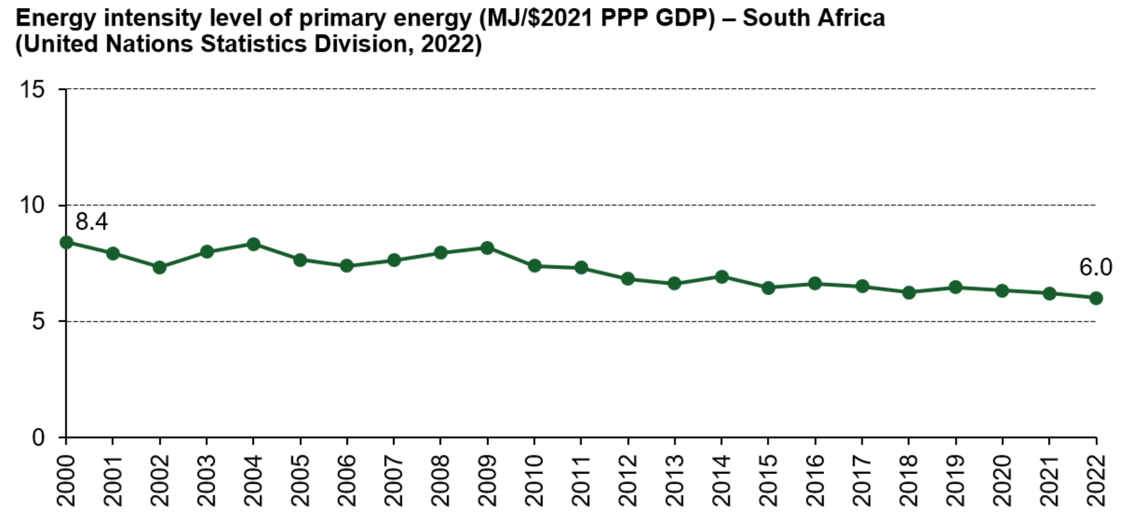


- **Renewable energy share in the total final energy consumption**: The contribution of renewable energy to the country’s total energy portfolio increased from 7.6% in 2014 to 9.7% in 2021 (United Nations Statistics Division, 2023). Efforts by the government to reduce South Africa’s dependence on coal-fired power resulted in a notable increase in private investment in renewables like solar and wind power. By 2022, most of these projects were feeding into the national grid.

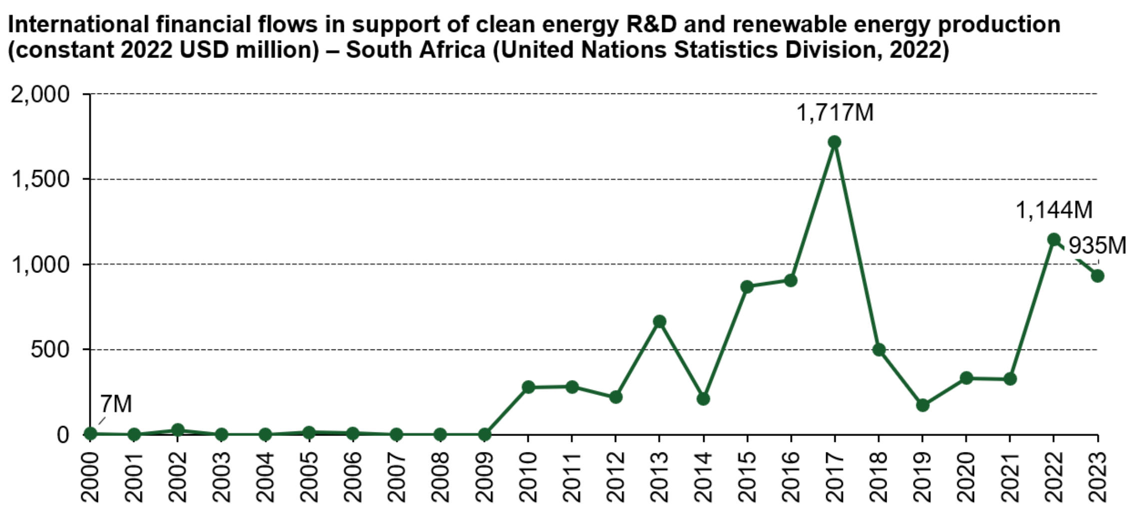
Renewable energy share in the total final energy consumption (%) – South Africa (United Nations Statistics Division, 2023)



- **Energy intensity level of primary energy**: The ratio between energy supply and economic output declined from 9.2 megajoules per constant 2017 purchasing power parity GDP (MJ/USD 2017 PPP GDP) in 2000 to 6.6 MJ/USD 2017 PPP GDP in 2021 (United Nations Statistics Division, 2023). Energy intensity is an indication of how much energy is used to produce one unit of economic output and a lower ratio shows that less energy is used to produce one unit of output. This, in turn, indicates economic development away from energy-intensive industries.



- **International financial flows in support of clean energy research and development (R&D) and renewable energy production**: Since 2009, South Africa has seen a significant increase in finance towards clean energy R&D and renewable energy production. In the decade ending 2022 (United Nations Statistics Division, 2023), this amounted to USD 6.9 billion when measured in constant (i.e., inflation-adjusted) 2021 dollars.



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 seen in the Electricity Regulation Amendment Bill and the Amended Schedule 2 of the Act that has 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. It is expected that the intervention to reform the electricity regulation regime is a step towards unlocking significant investment in new generation capacity in the short-to-medium term and looks to make progress in terms of achieving national energy security, as well as reducing the adverse impacts of load shedding, across the country.

Variable renewable energy (VRE) anchors the least financial cost industrialisation trajectory for South Africa's just transition. However, the shift of one mode of energy generation to another, the actual national absorptive capacity, and a misaligned pace of deployment of 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 R 1.5 trillion worth of infrastructure investment needs up to 2035, with R 711.4 billion alone ring-fenced for the electricity sector. From the above, there is a widespread view that South Africa has tremendous potential to realise a just transition. However, the maturing of an enabling policy environment and expansion of infrastructure to facilitate such a transition will be critical to realise growth opportunities that are emerging from the reforms currently underway. The section below outlines how policy and regulatory activations can support such a transition and realise the opportunities.

The South African energy landscape is experiencing rapid change and reform given the urgency to ensure energy security. As a testament to the government's commitment to address the energy crisis and to create 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 R 0.375 per kilowatt-hour (kWh) and R 0.344 per kWh for wind in 2021 (van Diemen, 2023). For comparison, the cost to generate electricity from coal, gas and nuclear is approximately R 1.03 per kWh, R 1.11 per kWh, and R 1.24 per kWh, respectively (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 systems and support the transition to renewable energy (SA-Gov, 2025).

- The introduction of **Battery Energy Storage Systems (BESS)** 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:** During the last 2 years, South Africa has seen many commitments to speed up the reformation 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 the development of market infrastructure, i.e., tariffs, licensing / registration, wheeling and trading frameworks as well as a fully-fledged power exchange (as envisaged as part of the Eskom unbundling process) is to fast-track the growth of all market segments. Sector coupling will also occur because of the reform (including EVs, green hydrogen, ammonia, etc.) that 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 realise 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 toward enhancing the grid, South Africa can harness its renewable energy potential, drive economic growth, and establish a sustainable energy future.
- **Decentralised ramp up:** South Africa is making progress towards a more decentralised electricity sector, especially 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 decentralisation and increased private sector involvement in South Africa’s electricity sector. However, it will take time to leverage the provisions of the Act to fully unlock the potential to ramp up decentralisation. 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 for 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 decarbonisation over the coming decades, what should the financing targets be for optimising 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, 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 policy, institutional, and regulatory (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 reliability of power supply, which disproportionately affects poorer households, be improved to meet SDG targets and NDP objectives, whilst 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 has, amongst other aims, 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 policy, institutional, and regulatory 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 completed a separate, parallel, literature review covering the 11 questions. See Appendix F for a mapping of the research questions to answers in the report.

2 Approach

2.1 Adapted World Bank 'Beyond the Gap' Methodology

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

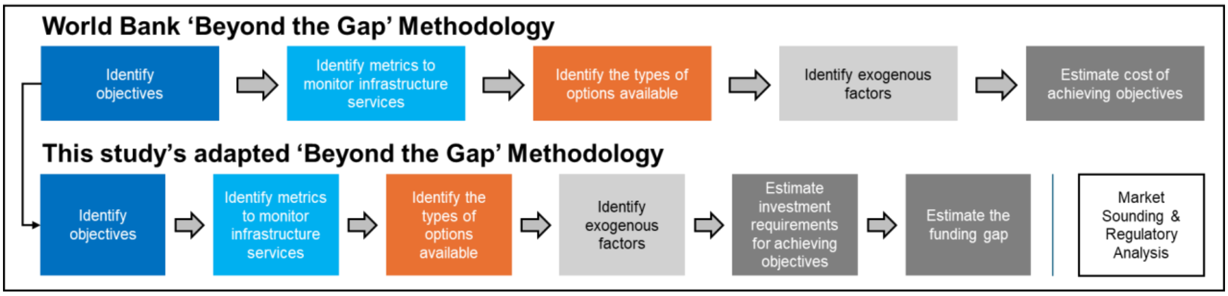


Figure 4: Adapted 'Beyond the Gap' Analytical Framework

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 link to the NDP (Chapter 5). These objectives are represented though the following metrics:
    - **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$_2$e by 2025, and 350 - 420 MtCO$_2$e by 2030 in line with South Africa's NDC targets.
        - As per SDG 7.2, increase substantially the share of renewable energy in the global energy mix 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 states a goal to 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, as well as overall stepping up of investments in energy-efficiency (RSA, 2021).

- **Identify metrics to monitor infrastructure services:** The metrics to monitor relate to South Africa’s NDC targets and performance against SDG 7 targets and its 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, 2023).
  - **The contribution of renewable energy to the country’s total energy portfolio:** In 2021, this figure stood at 9.7% (United Nations Statistics Division, 2023).
  - **Energy efficiency:** In 2021 (the latest available data) the ratio between energy supply and economic output was 6.6 megajoules per constant 2017 purchasing power parity GDP (MJ/USD 2017 PPP GDP) (United Nations Statistics Division, 2023).
  - **Electricity Availability Factor (EAF):** For the 2024 calendar year, South Africa’s EAF averaged 59.78% (Eskom, 2025).
  - **Affordability of technology options:** This metric will be expressed as a per annum cost for capital and operational expenditure in 2024 real terms, comparable across the various scenarios.
  - **Annual carbon emissions (CO_2e):** South Africa’s 2022 (the latest available data) emissions, were estimated at 436 $MtCO_2e$ (DFFE, 2024).
- **Identify the types of options available:** For the purposes of this study, three energy scenarios (including sensitivity analysis) were developed based on the following considerations:

  - **Pathway / scenario-specific inputs and assumptions**
    - Policy and regulations: 1) Carbon emissions from electricity, 2) Adherence to air quality standards, 3) Carbon Border Adjustment Mechanism (CBAM) and other export market regulations, and 4) Carbon emissions tax (CO_2 tax)
    - Generation: 1) Coal fleet decommissioning schedule, 2) EAF, 3) CCS viability timeline, and 4) Technology learning rates
    - Fuel prices
    - Capital: 1) Size of the market / funding, and 2) Cost of capital
  - **Universal inputs and assumptions**
    - Generation: 1) Embedded generation (on-site), 2) Commercial & Industrial Private wheeling Gx, 3) Grid expansion rate & generation build rate, and 4) Technology options (including load shedding / unserved energy)
    - Demand: 1) Universal access to electricity, 2) Demand and energy forecasts per sector, 3) Fuel switching, and 4) EVs
    - Regional electricity trade (via the Southern Africa Power Pool (SAPP))

- **Identify exogenous factors:** Exogenous factors that might influence the magnitude of funding required towards 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. Along with determining the options that are available, these exogenous factors influenced the determination of the range of the South African carbon budget to 2050.
- **Estimate costs of achieving objectives:** This step was completed in two broad ways. Firstly, extensive energy (electricity generation) and power systems (grid stability) (holistically termed "technical") modelling were conducted and informed by technical consultation sessions to obtain among others, new capacity build programme, energy mix, and total capital expenditure (Capex) estimations. The results were compared to the ranges that were identified in the parallel literature review study. In addition, a supplementary CGE modelling report will be produced to provide insight into the socio-economic impact stemming from the pathways / 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. A range of funding options and their respective mobilisation requirements (i.e., financial, policy, institutional, regulatory, or technical) were considered that could fill the remaining funding gap. 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 were conducted. Potential policy, institutional and regulatory (PIR) changes that will be required 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.

2.2 Phasing of Workstreams

The methodology was informed and supported through the following workstreams:

- **Literature review:** involved sourcing relevant literature and data for review and analysis in support of the adapted ‘Beyond the Gap’ methodology and answering the research questions in this report. It included incorporating new, relevant publications as these became available or were identified during the study period. While the literature review was conducted in a separate report, the content was utilised throughout this report to either substantiate statements or compare the outputs and findings to previous research.
- **Pathways development:** 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 infrastructure and power system scenarios, which were developed through a consultative process with the project partners, which included evaluating 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 under the three scenarios as developed under the pathways’ inputs:
- **Energy modelling**, with the objective to identify the least-cost infrastructure pathways to meet the emissions targets.
- **Power system modelling**, with the objective to understand the corridors’ current and future transfer limits and translate this into an approximation of 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 to include the additional grid infrastructure cost required to facilitate the high penetration of inverter-based variable renewable energy generation and storage.

  Through energy[7] and power systems modelling (collectively termed “technical modelling”), these scenarios provide the capital and operational expenditure per annum – 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. This informed key aspects including the potential funding gap, the obstacles and enablers in relation to raising or allocating additional funds towards energy infrastructure, as well as 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.

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[7] *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, coal mines, etc.*

- **Funding gap calculation:** Based on the findings from the literature review and 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, a funding gap range was estimated across the three scenarios.
- **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. It included identifying the main strengths and gaps of the policy, institutional, and regulatory (PIR) framework currently in force related to funding energy infrastructure in South Africa. In addition, it considered international best practices regarding energy funding mechanisms to advance renewable energy goals. Based on these inputs, and those obtained from the market sounding exercise, concrete recommendations are made for regulatory improvement and reform towards achieving a competitive, resilient, and sustainable electricity sector based on the funding gap and modelling outlined in the previous sections.

3 Pathways and Scenarios Development

3.1 Local Development Pathways

This section describes the range of high-level pathways which the project team, with inputs and oversight from the Project Steering Committee, envisaged at the inception stage. The three pathways provide the overarching guidelines for the conditions and limitations under which the associated scenarios must be modelled. This collective has made specific decisions regarding the variable inputs based on the literature, as well as the assumptions to be applied when modelling the three scenarios under each of the three pathways. These decisions extended to the sensitivities the project team applied when modelling the three scenarios 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) (DFFE: SA-LEDS, 2020).

In essence, under each of the three high-level pathways, the associated scenario to be modelled needs to identify the energy infrastructure investments required between 2024 and 2050 to achieve:

- **Energy security:** Ensuring sufficient supply of electricity within the South African electricity system to ensure economic and human development.
- **Affordability:** From a technology, financing (cost of capital) and end-user perspective, and
- **Carbon budget:** NDCs, indicating South Africa’s “fair share” of the remaining GHG emissions allowance, related to the long-term temperature goal of the Paris Agreement between 2010 and 2050.

3.2 Local Development Pathways within the Global Context

The Intergovernmental Panel on Climate Change (IPCC) special report (Masson-Delmotte, *et al.*, 2018) focuses 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 doesn't exclusively revolve around global cooperation, it does emphasise the importance of international collaboration and coordination to effectively address the challenges of climate change. The level of collaboration and coordination will have a direct impact on the access to and cost of capital to finance green energy infrastructure development and the ability for the globe to manage its collective carbon budgets. Figure 5 frames the international development pathways with three high-level scenarios across the horizontal:

- A **global alignment** to keep global warming to below 1.5 degrees Celsius in relation to pre-industrial levels as per the Paris Agreement.

- A **fragmented** world where only certain countries achieve their NDC targets and warming is limited to below 3 degrees Celsius.
- A **Business-as-usual (BAU) scenario** where climate commitments generally stall and fail, with global warming exceeding the 3 degrees Celsius threshold.

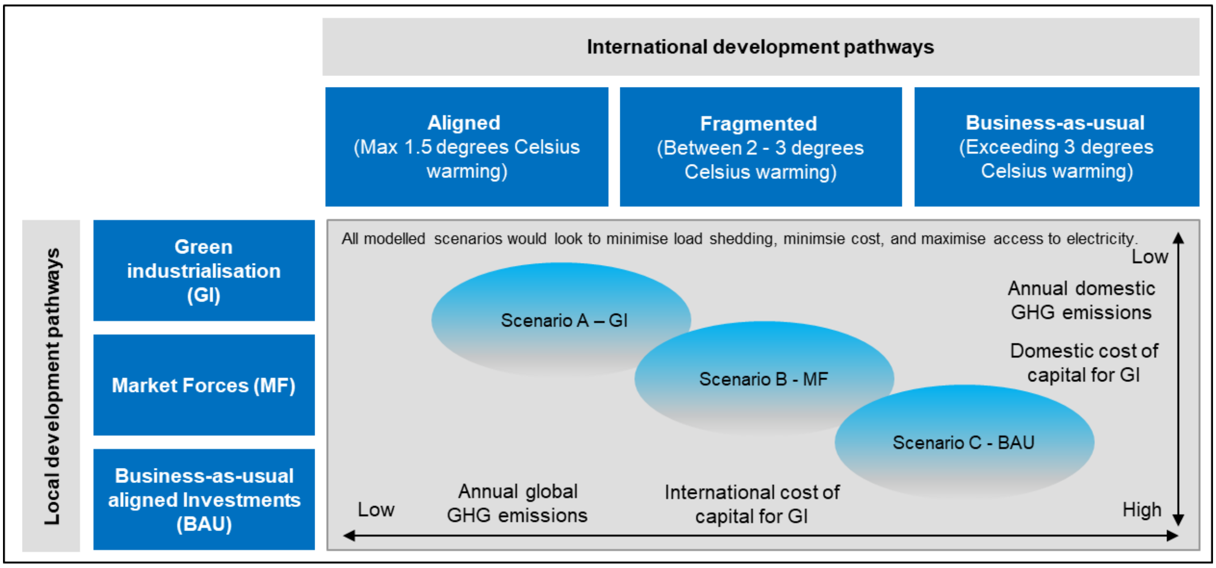

Figure 5: Summary of Scenarios Under the International and Local Development Pathways

Sources: IPCC, 2018; JET-IP, 2022; Project Working Group, 2023

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 plan also 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[8] within the global context, some narratives that will shape the different modelling scenarios are defined. For ease of reference, the three scenarios take their names from the local development pathways.

- The **Green Industrialisation** 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 mandated air quality compliance by 2030. Under this pathway, a large market exists for GI finance, and

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[8] The Just Energy Transition Investment Plan (JET-IP) (The Presidency, 2022) is aligned with the updated NDC emissions targets and show 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 the overall emissions range is estimated to fall within a 2 $GtCO_2e$ (Green Industrialisation pathway) to 3 $GtCO_2e$ range (Market Forces pathway).

cost of capital is low and accessible for renewable energy technologies, while cost of capital for fossil fuel technologies attracts a premium. Also, new technology learning rates are optimistic (i.e., costs reduce), competition for fossil fuels is low (which results 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 to its NDC targets, but that 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 remain within the strict adherences to air quality standards and carbon policies. Under this pathway, a carbon emissions target of 3 Gt by 2050 is assumed for the electricity sector and air quality 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 and compliance with air quality standards (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.

It is important to note that the high-level pathway-specific assumptions that underpin the final scenarios are not always unique to each, and these three scenarios as depicted as overlapping in Figure 5.

3.3 Defining the Scenarios to be Modelled

The inputs and assumptions into the model[9] are as follows:

1. Pathway-specific inputs and assumptions: These inputs, decisions and assumptions are related to the specific scenario to be tested, for example, adherence to air quality regulations, and
2. Universal inputs and assumptions: These are consistent across the scenarios and not directly influenced by the specific scenario, for example, the development of embedded generation / rooftop PV.

It must be noted that some "inputs" are in the form of constraints / limits, and the model may not necessarily reach each of these constraints / limits. For example, in Scenario C where the decommissioning timeframe for existing coal plants is extended, the model will still determine the actual decommissioning year based on other constraints such as carbon budget adherence and minimising the overall system cost. Therefore, Table 4 and 5 set out the conceptual framework of non-exhaustive, high-level inputs and assumptions across the three scenarios.

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[9] *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 Industrialisation-Orientated Pathway Assumptions per Scenario

Area	Model parameter / descriptor	Scenario A Green Industrialisation	Scenario B Market Forces	Scenario C Business-as-usual
Policy & regulations	Carbon emissions from electricity sector	2.0 $GtCO_2e$	3.0 $GtCO_2e$	No limit
	Adherence to air quality standards	Mandated by 2030	Mandated by 2035	Not mandated
	Carbon Border Adjustment Mechanism (CBAM) and other export market regulations[10]	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, December 2023)	Pathway 1 (IRP 2019, with adjustments) (University of Pretoria General Equilibrium Model, December 2023)	Pathway 2 (Delayed decommissioning timeline relative to pathway 1) (University of Pretoria General Equilibrium Model, December 2023)

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

	Coal fleet EAF[11]	High 65% from 2023 to 70% by 2035, 70% to end, except Medupi and Kusile which are 73% from 2025	Medium 65% throughout, except Medupi and Kusile which are 73% from 2025	Low 60% throughout, except 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 / learning rates	Optimistic (Likely scenario from Meridian Economics, Review of the Draft IRP 2023, March 2024)	Moderate (Base Case scenario from Meridian Economics, Review of the Draft IRP 2023, March 2024)	Pessimistic (Stress scenario from Meridian Economics, Review of the Draft IRP 2023, March 2024)
Fuel Prices	Coal and natural gas	Low (Net Zero Emissions by 2050 Scenario (NZE) from IEA WEO, 2024)	Moderate (Announced Pledges Scenario (APS) from IEA WEO, 2024)	High (Stated Policies Scenario (STEPS) from IEA WEO, 2024)
Capital	Size of market / funding[12]	Limited local and international funding available for zero carbon generation options. Finance for carbon intensive generation is even more expensive.	Local and international funding available for zero carbon generation options. Finance for carbon intensive generation is more expensive.	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).

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[11] *EAF is highest under the Green Industrialisation scenario because older/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.*

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

	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

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

Area	Model parameter / 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 & generation build rate	No constraints applied in terms of maximum grid expansion or generation build rates
	Technology options	Refer to Section 4.3.5
Demand		Data from the 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 incorporated.

Area	Model parameter / descriptor	Assumption
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 transmission infrastructure that meets the specified constraints (e.g., least cost, energy for all, CO_2 budget, electricity demand, etc.) over the projected timeframes (2030, 2040, 2050). The Pathways define the scenarios and associated parameters and constraints to be modelled within the energy model.

For the period up to 2030, steady state power system analysis was used to quantify the transmission constraints. Beyond 2030, the energy model ignores the transmission corridor constraints (i.e., adopting a "copper plate" approach) and fully optimises for the generation only. Thereafter, the transmission corridors required to unlock and ensure affordable electricity and security of supply were identified (i.e., using resultant energy flows from the energy model). 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 selected by the energy model will be used as inputs to the supplementary CGE model report to understand their respective impacts on society and the economy.

4.2 Methodology

4.2.1 Open-Source Energy Modelling System (OSeMOSYS)

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

OSeMOSYS computes the energy supply mix (in terms of generation capacity and energy delivery) which meets the energy services demands every year and in every time step of the case under study, minimising the total discounted costs. It can cover all or individual energy sectors, including heat, electricity, and transport. These energy demands can be met through a range of technologies which have certain techno-economic characteristics and draw on a set of resources, defined by certain potentials and costs. Policy and project scenarios may impose certain technical constraints, economic realities, or environmental targets. As with most long-term optimisation modelling tools, OSeMOSYS assumes a unique decision-maker, perfect foresight, and competitive markets (Howells, 2008).

Results from OSeMOSYS include new generation capacity build, existing and new generation costs, renewable energy penetration as well as sensitivity analysis which helps understand how changes in input parameters, such as electricity pricing assumptions, influence the overall energy system and the success of procurement and optimisation strategies.

4.2.2 Model Management Infrastructure (MoManI)

OseMOSYS has various user interfaces available to select from, including ClickSAND, the Low Emissions Analysis Platform (LEAP), and the Model Management Infrastructure (MoManI). MoManI, which is an open-source interface that has both an online and a stand-alone version, was adopted for this assignment because of its flexibility and better user interface relative 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 and assess flexibility options, including energy storage, demand response, and flexible generation technologies. It operates across various timescales (e.g., short-term operational decisions through 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 suitability, and where required refine the proposed capacities by analysing the hourly dispatch, to ensure practicality and realism of the system operators merit order dispatch and the inherent ramping constraints on other technologies.

4.2.4 Energy Model Configuration

The energy model flow logic is graphically represented via a Reference Energy System (RES) diagram shown in Figure 6. The RES diagram illustrates the primary energy sources (including fuels and renewable energy resources) assumed in the model, all the generation technology options (existing, planned and potentials), 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.

It is important to note that for simplification purposes, the RES is illustrated at provincial level and serves as a high-level view of the building blocks which represent the entire South African electricity system (refer to figure below). A higher resolution version of the RES diagram is provided in Annexure A: Reference Energy System .

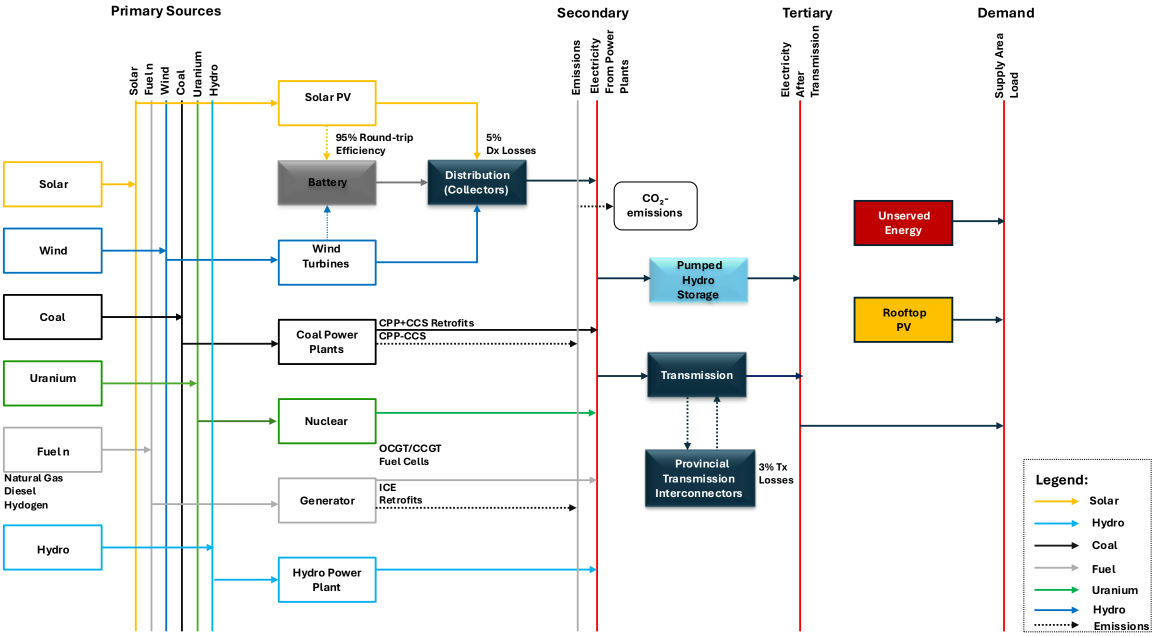

Figure 6: Reference Energy System

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 which were in R were converted to USD at an exchange rate of 18.8 R/USD.
- All future monetary values in the model are in 2024 real terms, i.e., inflation / escalation has been excluded. The only costs which change over time are the gradually reducing costs of solar, wind, battery energy storage, and carbon capture and storage, due to technology learning rates.
- The model assumes a real discount rate of 8% (as per the Draft IRP 2023 and Meridian Economics Review of the Draft IRP 2023).
- Two types of typical day were modelled, i.e., summer weekday, and winter weekday. Each typical day consists of 24 one-hour "time slices".
    - A reserve margin of 15% was assumed in the model.
    - 10 node model with one node per Eskom supply area.
    - 28-year modelling period from 2023 to 2050.
- The model calculates for discrete years:
    - 2023 (annual).

  - 2024 (annual).
  - 2025 (annual).
  - 2030 (5-year block representing 2026 to 2030, inclusive).
  - 2035 (5-year block representing 2031 to 2035, inclusive).
  - 2040 (5-year block representing 2036 to 2040, inclusive).
  - 2045 (5-year block representing 2041 to 2045, inclusive), and
  - 2050 (5-year block representing 2046 to 2050, inclusive).

4.3.2 Demand

Electricity demand was based on data obtained from the single node hourly model for scenario-based demand projections (herein referred to as the "demand forecast") developed by the University of Cape Town's Energy Systems Research Group (ESRG). The demand forecast was used to obtain hourly demand profiles and total national annual electricity consumption per annum over the period 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.

Electricity demand for electric vehicles (EVs) is included in the demand forecast. The EV electricity demand as a portion of total national demand per year for the reference case from the demand forecast is shown in Figure 7.

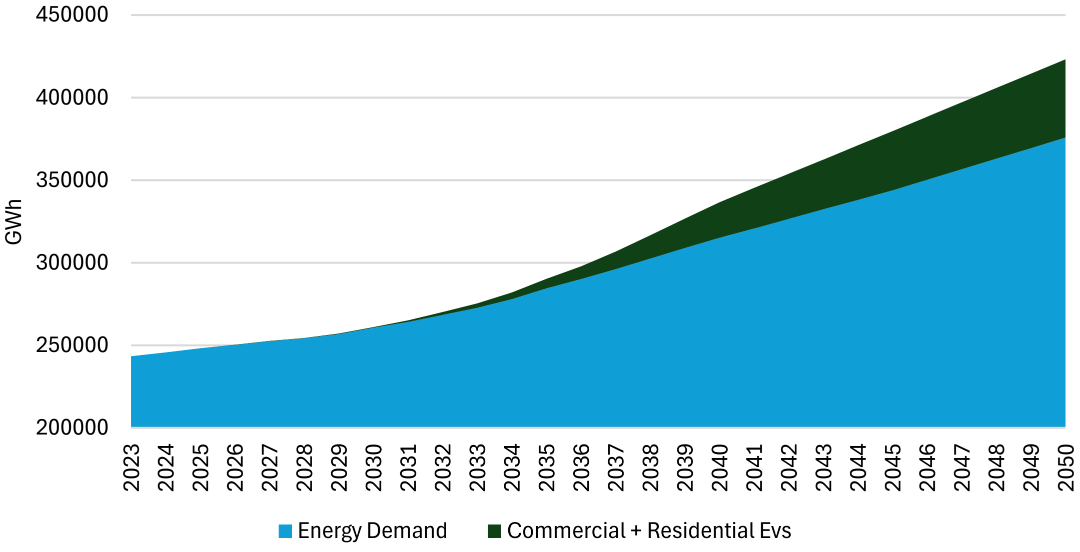

Figure 7: Electric Vehicles Demand as a Portion of Total Demand

Source: Single node hourly model for scenario-based demand projections developed by UCT's ESRG 2023

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

Scenarios addressing significant changes in Sasol's electricity demand because of future business model changes (e.g., changes in product portfolio, scaling down, shutting down, etc.) are not included in the demand forecast. While the project team was able to engage with Sasol during the study, the information provided regarding its future plans was extremely wide-ranging. Industrial demand in the demand forecast assumes a limited level of energy efficiency improvements and fuel switching but is primarily driven by economic growth.

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

Rooftop PV was included in the demand forecast; however, this was removed from the demand included in the energy model and was instead modelled as a standalone generator (refer to Section 4.3.4 for further discussion on this).

Eskom's Transmission Development Plan (TDP) 2023 was used to apportion the national demand per Eskom supply area. Note that the TDP includes ten supply areas, i.e., one per province plus one additional for the Hydra Central area. However, the demand for Hydra Central was set to zero as this area is primarily an entry point for new generation capacity into the grid and itself is not a considered consumer / demand.

Figure 8 and Figure 9 illustrate the hourly demand profile and energy demand per supply area, respectively.

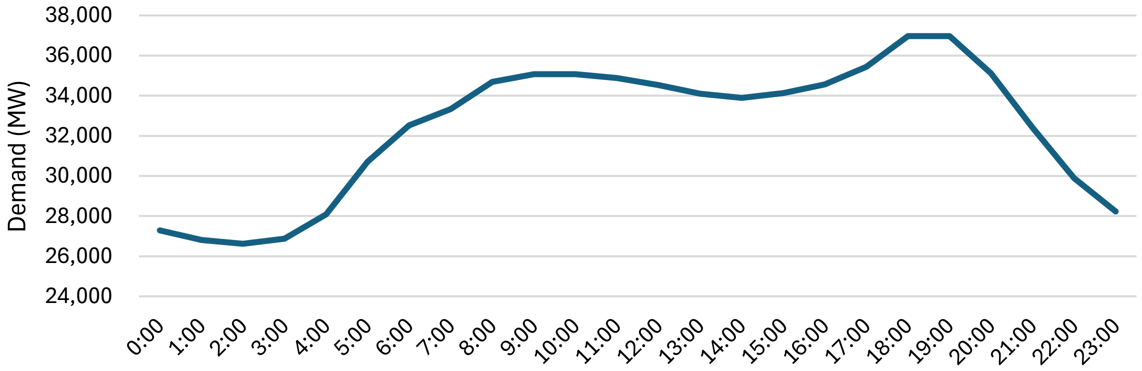

Figure 8: National Demand Profile

Source: Single node hourly model for scenario-based demand projections developed by UCT's ESRG, 2023

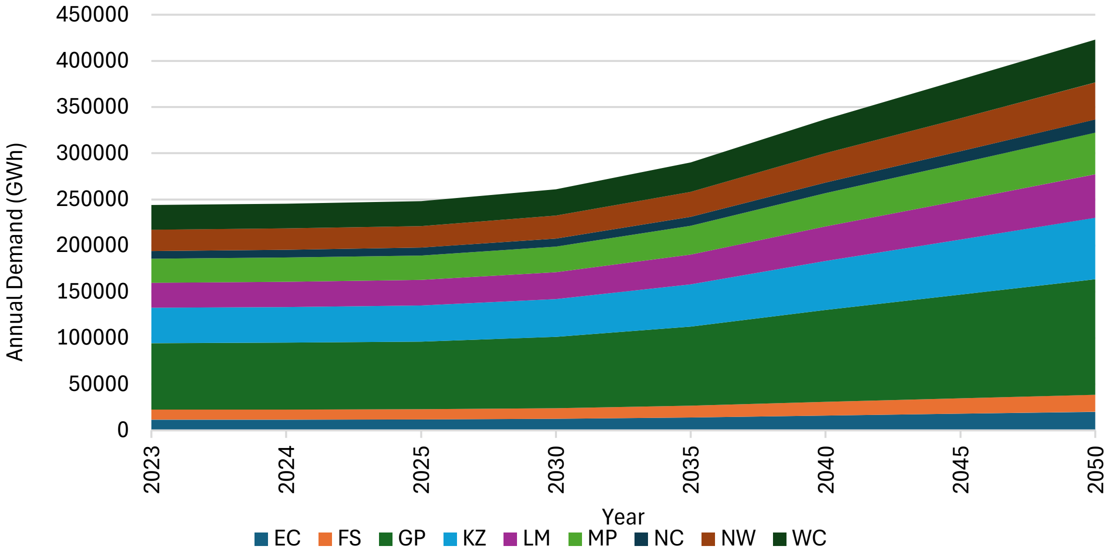

Figure 9: Energy Demand Per Supply Area

Source: Single node hourly model for scenario-based demand projections developed by UCT's ESRG, 2023

4.3.3 Eskom Generation

All Eskom generators and coal fleet were modelled individually with distinct installed capacities obtained from various sources including the University of Pretoria's General Equilibrium Model (UPGEM) (Horridge, 2012) - 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 of the Eskom power plants was adjusted for each scenario:

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

Plant-level efficiency of the Eskom coal fleet is not readily available to the public. To address this challenge, the model assigns plant efficiency values based on the technology of each plant (e.g., coal, OCGT, nuclear, etc.), thus using the established average efficiency ranges associated with the different power generation technologies.

Decommissioning pathways for Eskom's coal fleet were obtained from the UPGEM model. The data was last updated in December 2023. The dataset contains three distinct pathways for Eskom's coal fleet decommissioning which are as follows:

- 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 IRP2019 with minor adjustments for known delays and grid constraints, was adopted for Scenarios A and B. Pathway 2 was adopted for Scenario C. Figure 10 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 is allowed to stop dispatching a power plant before its deadline (e.g., if this is required to meet carbon emissions constraints or due to lower cost alternatives being available).

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 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, i.e., retaining the power plant in a reasonable condition as "insurance" for unforeseen security of supply risks.

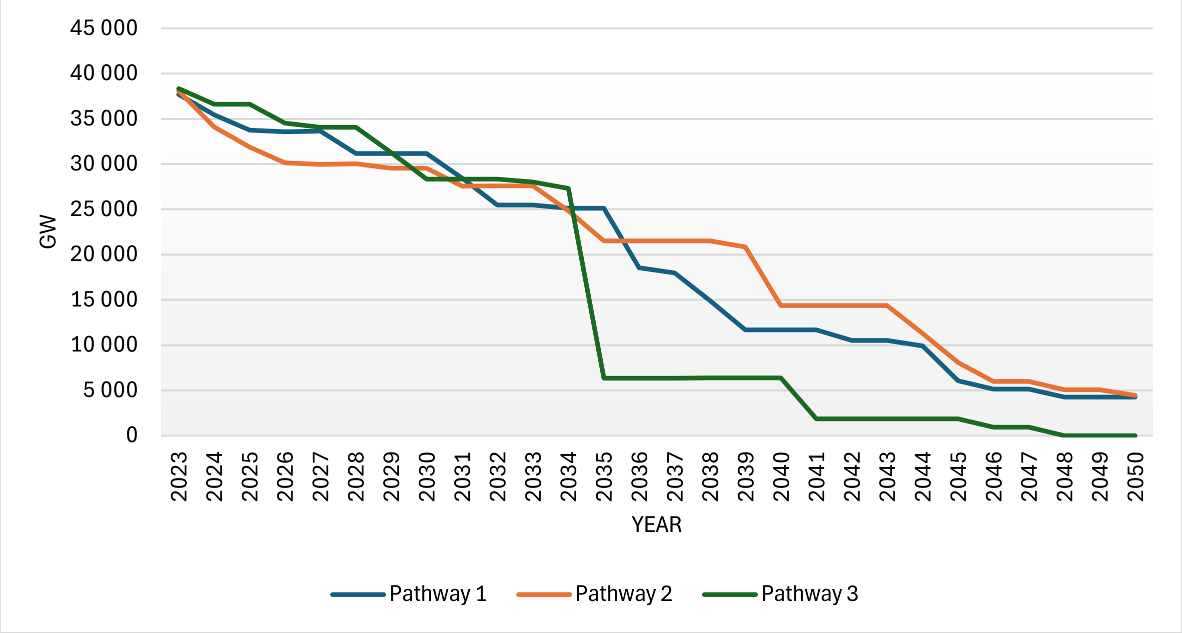

Figure 10: Eskom Coal Fleet Decommissioning Pathways

Source: Input Dataset from University of Pretoria's General Equilibrium Model (UPGEM)

4.3.4 Other Existing and Committed Generation

The Renewable Energy Independent Power Producers Procurement Programme (REIPPPP Bid Windows 1 to 6) data published by the Department of Mineral Resources and Energy (DMRE, 2023a) in South Africa served as the foundation for the assumptions made on the existing, committed, and planned generation capacities for renewable energy (wind and solar) projects. The following assumptions regarding the projects' commercial operation dates were made:

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

For capacity factors of the renewable energy projects, refer to **Error! Reference source not found.**.

Based on the Energy Storage Independent Power Producer Procurement Programme (ESIPPPP) Round 1 to 3, and the Eskom BESS programme, the model assumed a total of 2 100 MW of BESS capacity to 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 to power to be 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 (Cahora Bassa hydro power plant) will end in 2030.

4.3.5 Rooftop PV

Rooftop PV systems were modelled as a stand-alone technology supplying the load directly (i.e., generating at the point of consumption) as shown in Figure 6. This approach minimises transmission losses, and demand on the main grid. Eskom's weekly system status reports were used to quantify the current level of rooftop PV.

A nominal growth rate assumption was applied to the current level of rooftop PV, as agreed with the client during technical workshops.

Figure 11 shows the quantity of existing and forecasted rooftop PV capacity in Gigawatts (GW) per supply area per year. Hydra Central is not included since it is assumed to have negligible demand and therefore no need for rooftop PV.

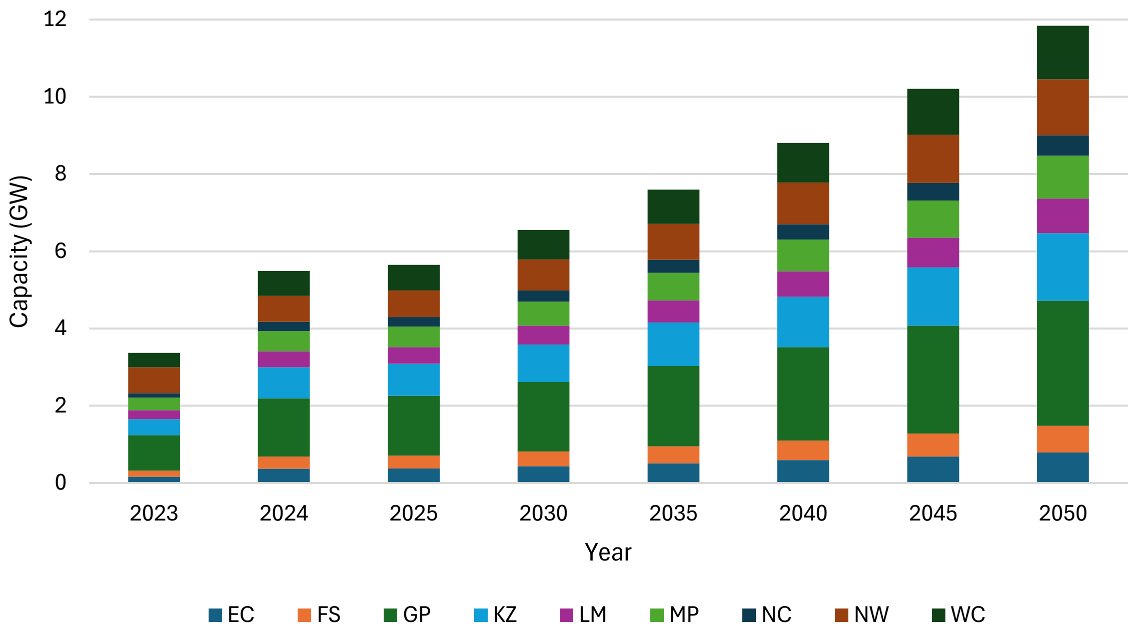

Figure 11: Rooftop PV Capacity Forecast

Source: Input Dataset from University of Pretoria's General Equilibrium Model (UPGEM)

4.3.6 Fuel Prices

Fuel prices for diesel and uranium were obtained from the Meridian Review of the IRP 2023 report, with no escalation applied during the modelling period (Meridian Economics, 2024). 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 change over time according to these forecasts. Scenario A in this study aligns well with the NZE scenario in the IEA WEO, similarly, Scenario B aligns well with the APS scenario, and Scenario C 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 Retrofits

The total cost of carbon capture and storage (CCS) is comprised of the cost of capturing, transporting and storage of the carbon.

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

Retrofitting an existing coal plant with CCS also results in a reduction of 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, the most common being pipeline, rail and truck. Trucks are most economical for smaller quantities and distances up to 200 km. Pipelines and rail are economical for larger distances and greater quantities. Mahler and Arndt (2024) report prices for various transportation options and distances involved for carbon in the South African context. For 200 to 750 km, transporting carbon via pipeline is most practical, and for onshore, costs 1.7 to 6.1 USD / tonne CO_2, and for offshore, costs 3.8 to 32.4 USD / tonne CO_2.

Kearns, Liu and Consoli (2021) have presented a range of values for storage of CO_2 based in the US Gulf Coast, the cost of storage is dependent on the site and technology selected. The range for geological storage is from 2 to 20 USD / tonne CO_2, with the lower end of that range being more representative of an onshore geological site and the higher end of the range being more representative of an offshore geological site.

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

Table 8: Cost Range for Carbon Transport and Storage

Mode of Transport	**Transport** (USD / tonne CO_2)	**Storage** (USD / tonne CO_2)	**Total Cost** (USD / tonne 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, a cost of 30 USD / tonne CO_2 was selected for inclusion in the model. This represents the high end of the cost range for onshore pipeline and middle-of-the-range for offshore pipeline.

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

- Scenario C: 2040

Selection of whether the plant will be retrofitted is made by the model, based on lowest cost optimisation and emissions constraints.

It is worth noting that by July 2024, approximately 50 commercial CCS facilities were operational around the world, with a combined capacity of 51 MtPA CO_2 (Megatonne per annum). There are 45 projects under construction with a combined capacity of 51 MtPA CO_2, and another 247 projects at an advanced stage of development with a combined capacity of 180 MtPA CO_2. 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 MtPA CO_2. The CO_2 is used to enhance the 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 MtPA CO_2 and sequester the carbon in a saline formation after two of the 660MW units are retrofitted for CCS (Baringa Partners LLP, 2024).

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

4.3.8 New Technology Options

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

- Combined cycle gas turbine fuelled by natural gas (NG-CCGT),
- Open cycle gas turbine fuelled by natural gas (NG-OCGT),
- Internal combustion engine fuelled by natural gas (NG-ICE),
- Nuclear power plant,
- New 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 battery energy storage system (BESS).

Not all technologies are practical to construct in all supply areas, e.g., proximity to natural gas infrastructure, coal resources, water, etc. The table below shows the new generation and storage technology options which 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 allow commissioning of new generation and storage technologies from 2030 and beyond, except for hydrogen fuelled open-cycle gas turbines (OCGT) and nuclear power plants (to account for technology availability and construction timeframes, respectively). Prior to 2030, only the committed generation projects (as discussed in Section 4.3.4) are built by the model. The following assumptions were made for nuclear power plants and hydrogen fuelled OCGTs, based on research:

- Nuclear: Available from 2040 to 2050 (due to project development / construction timeframes), and
- Hydrogen OCGT: Available from 2045 to 2050 (due to technology development timeframes).

Technology costs, efficiencies, and lifetimes were derived from comparison of various data sources, including:

- National Renewable Energy Laboratory (NREL).
- Electric Power Research Institute (EPRI), and
- Meridian, Review of the IRP 2023 (Meridian Economics, 2024).

The table below outlines the capital costs (funds or total overnight costs to acquire or build a plant - Capex), fixed operation and maintenance (FOM) costs (associated with regular, ongoing maintenance and operation of the plant, 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.

CO_2 emissions associated with each fuel were obtained from the IEA database. It is acknowledged that there are CO_2 emissions associated with the manufacturing, construction, and decommissioning of power plants, however this was excluded from the model on the basis that CO_2 emissions associated with operation / fuel consumption are much more significant. The result is that the table below reflects zero CO_2 emissions for nuclear which is clearly 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 / Capacity Factor[13] (%)	CO_2 Emissions (tCO_2 / MWh)	Lifetime (years)
NG-CCGT	2023 to 2050	886	2	14	50 / 55	0.46	30[14]
NG-OCGT	2023 to 2050	677	3	14	35 / 44	0.65	
NG-ICE	2023 to 2050	1,785	16	14	40 / 90	0.57	
NUCLEAR	2023 to 2050	6,434	91	9	30 / 95	-[15]	
COAL-CCS	2023 to 2050	3,830	116	25	23 / 70	-	
PHS	2023 to 2050	1,396	18	-	40 / -	-	
SOLAR PV	2023	940	19	-	- / 27 to 34	-	25
	2025	940	19				

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[13] *Capacity factors shown here are an upper limit. The energy model dispatches according to lowest cost, without exceeding the capacity factor.*

[14] *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.*

[15] *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 / Capacity Factor[13] (%)	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 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 GNR 893 as set out in National Environmental Management: Air Quality Act, 2004 (Act No. 39 of 2004). For plants being decommissioned before

31 March 2030, a once-off suspension can be applied, otherwise power stations are required to adhere to the MES. Table 11 shows the limits applicable to coal-fired power stations.

Table 11: Solid Fuel Combustion 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. To reduce the sulphur dioxide emissions, flue gas desulphurisation (FGD) is often employed and is a costly retrofit. Oxides of Nitrogen are often controlled by combustion optimisation and controlling excess air.

There is limited publicly available information regarding the cost of air quality retrofits for the Eskom fleet. However, Eskom has reported that full compliance of its coal fleet to meet the MES is estimated at over R300 billion. This R 300 billion was divided by the total coal fleet capacity, to give an approximate R/MW rate, which was then be applied to each coal plant based on MW capacity for that plant.

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

- Scenario A: 2035
- Scenario B: 2035
- Scenario C: Not mandated

The model has the option to spend the retrofit Capex and to either 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 OEG’s internal projects database (i.e., a combination of actual historical production data and theoretically derived production data based on historical weather measurements). The production data for each supply area was aggregated at hourly resolution to provide a total hourly production profile per supply area. Probability distribution curves were plotted for each technology for each supply area. From these curves, summer and winter days which represented P50 and P90 production levels were selected.

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 12 and Figure 13 below illustrate the P50 summer day profiles for wind and solar PV using Free State as an example.

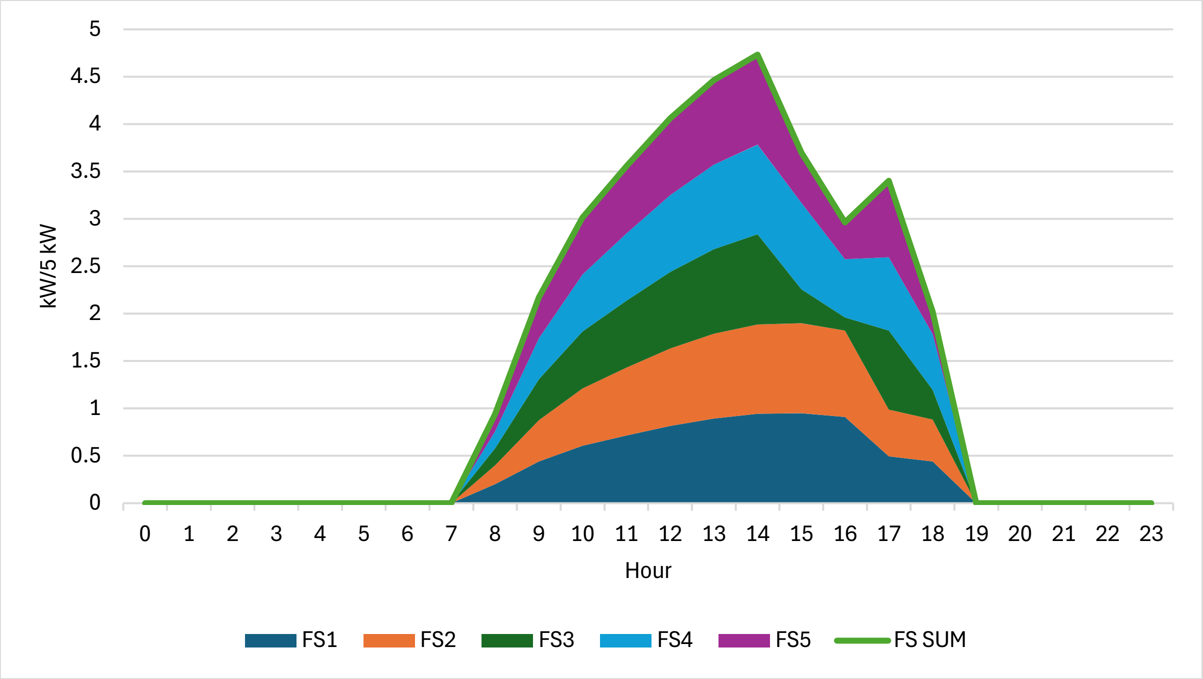

Figure 12: Free State P50 Summer Day – Solar PV

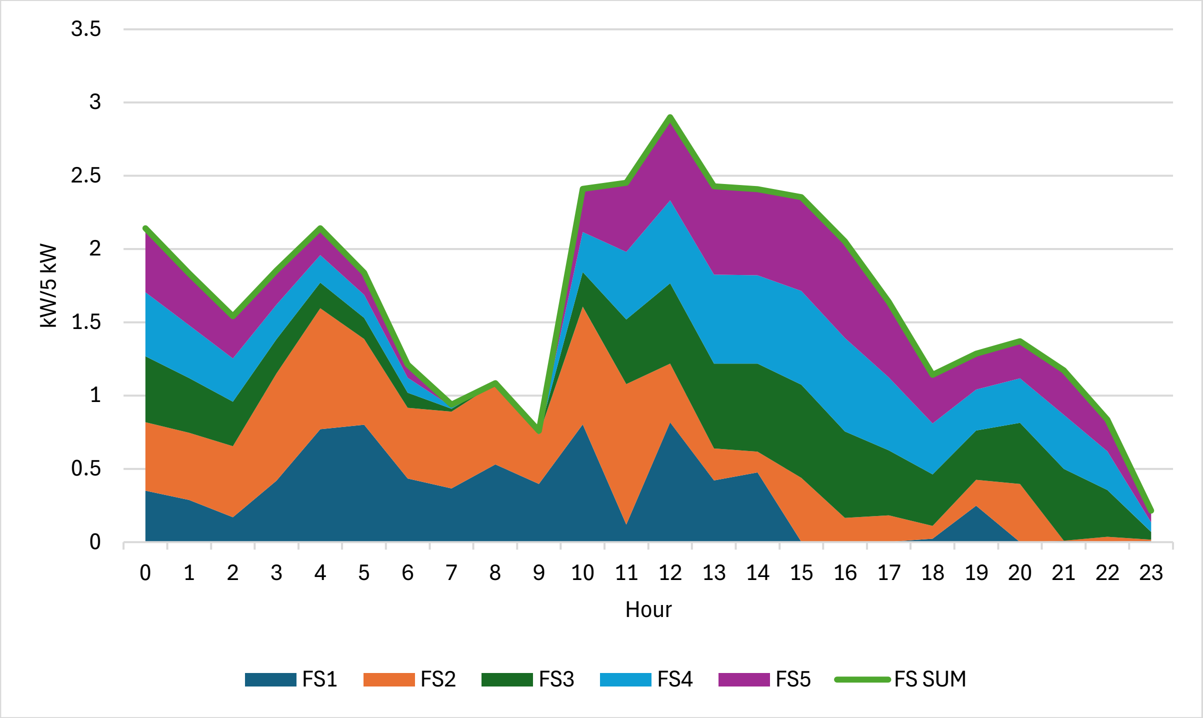

Figure 13: Free State P50 Summer Day – Wind

4.3.11 Transmission Corridors

Eskom's existing transmission corridors (i.e., high-voltage transmission lines that connect the electricity grids of different regions or provinces, allowing power flow between these areas) between the supply areas were established within the energy model. The model was restricted to only increase the capacity of these existing corridors, as opposed to building entirely new transmission 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 unrestricted in the model (except for the transmission and distribution losses).

Figure 14 shows the ten supply areas marked in red boundary lines and the transmission corridors illustrating power flow between them.

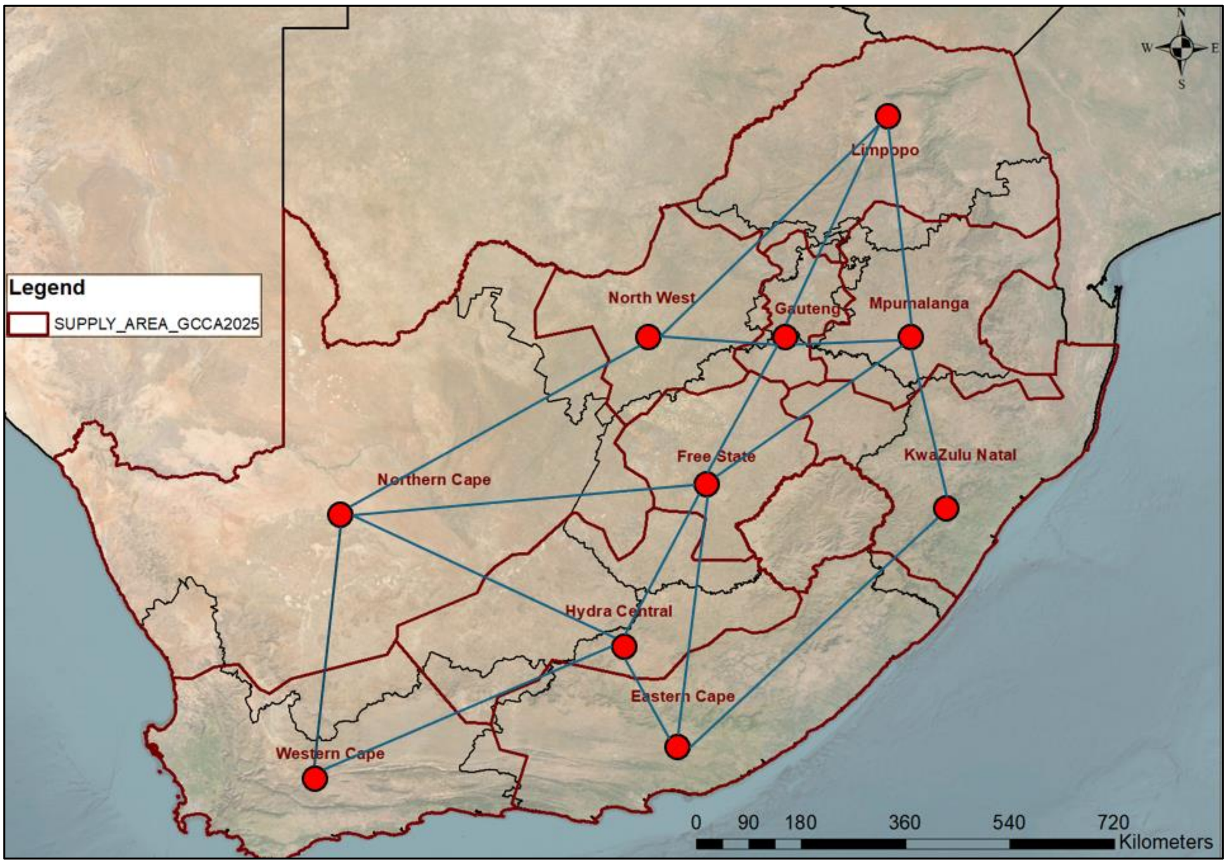

Figure 14: Transmission Corridors

4.3.12 Wind and Solar Collector Networks

Variable renewable energy sources such as wind and solar PV plants are generally distributed and connected via the sub-transmission / distribution network to collect the generated power to the main transmission stations (MTS) and then evacuate via the local transmission network to the demand centres through the transmission corridors. This is different to conventional power plants that have a dedicated transmission station to collect the power (due to typical sizes >300MW). In addition, there are benefits for retaining the solar and wind facilities below 300MW to safeguard the grid against the impact of cloud cover and or wind fluctuation in a localised area, as such this study did not anticipate the development of mega-solar or wind parks (>1 000MW per site). This results in additional sub-transmission investment required to connect VRE power plants to the grid versus the conventional thermal plants.

4.3.13 Capex Premium as Proxy for Cost of Capital Premium

Scenarios A and B assume that the cost of capital for new fossil fuel generation is higher than 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%, and after hedging and intermediation may be on-lent by development finance institutions 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 energy model (i.e., OSeMOSYS) does not have functionality to define different cost of capital for different technologies – it only allows for a global discount rate which is applied to all future costs in the model (which is set to 8% under 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 agreed through consultation was to incorporate a premium on the Capex cost of new fossil fuel generation as a proxy for the premium on cost of capital as the proportionate debt service and equity base will increase in line with the premium on the Capex cost.

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

To translate the Capex premium into an equivalent (approximate) increase on the all-in risk premium on debt, a demonstration calculation was conducted, as set out in Table 13. Assuming that the Capex premium is the same as a premium on the weighted average cost of capital (WACC), and assuming a "typical" debt / equity split, "typical" equity rate of return, and current JIBAR base rate plus a risk premium, it is possible to calculate the assumed impact on the all-in risk premium on debt.

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

It should be noted that this is a simplistic approach which ignores factors such as debt tenor, amortisation profile, tax, etc.

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

Parameter	Scenario A	Scenario B	Calculation
Equity portion	30%	30%	(A)
Debt portion	70%	70%	(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%	30%	(J) = A
Debt portion	70%	70%	(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

Scenario A generation capacity results are shown in Figure 15.

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

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

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

Battery storage in Scenario A grows substantially—from 11 GW in 2030 to 31 GW in 2040, then to 53 GW by 2050—representing a nearly 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 VRE resource is low.

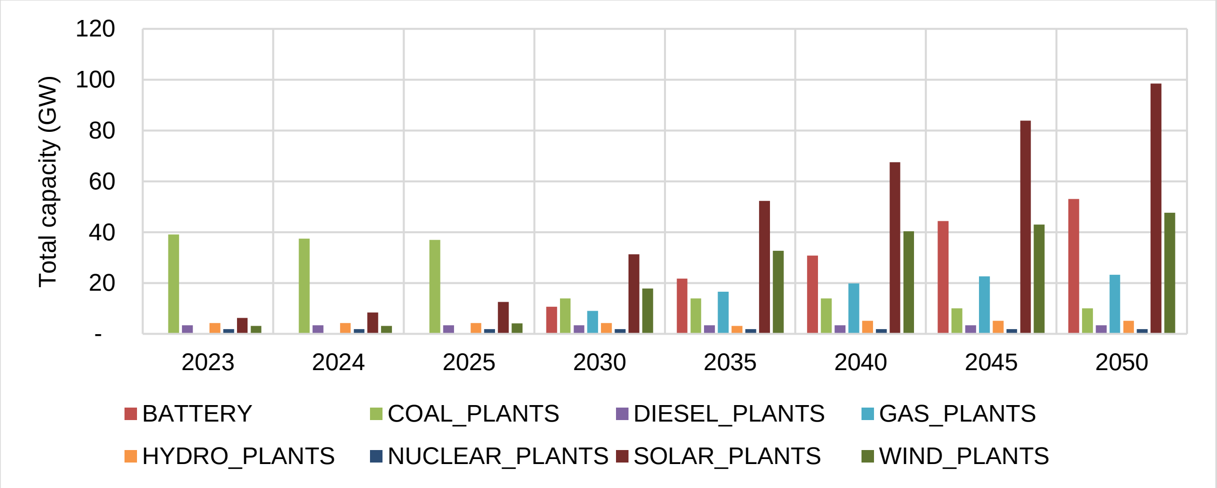

Figure 15: Scenario A Generation Capacity

Scenario B generation capacity results are shown in Figure 16.

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

By 2040, as AQ retrofits trigger decommissioning of older coal units, coal's contribution declines to approximately 9% of the total generation capacity, with gas-fired generation rising (16% of installed capacity) and VRE substantially increasing (from 39% of installed capacity in 2030 to 65% in 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 around 18%, while coal with CCS plays a minor role at 7% of installed capacity. Nuclear and hydro provide around 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.

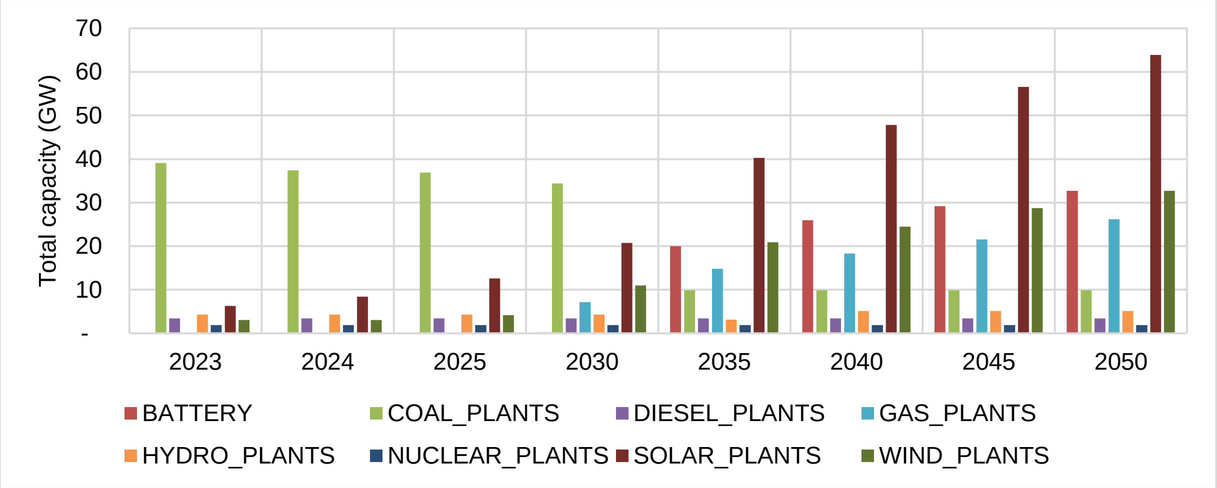

Figure 16: Scenario B Generation Capacity

Scenario C generation capacity results are shown in Figure 17.

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

By 2040, total capacity in Scenario C grows to roughly 109 GW. Solar increases to about 38% of installed capacity and wind to around 21%. Coal's share declines to roughly 14%, and gas rises to around 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 around 134 GW. In this configuration, solar remains at approximately 38% of installed capacity, wind increases to about 24%, gas expands to roughly 22% and coal drops to about 6%. Batteries in Scenario C increase from 7 GW in 2030 to 46 GW in 2040, and further to 55 GW by 2050—a dramatic increase early on (over 500% from 2030 to 2040) followed by a modest increase (~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.

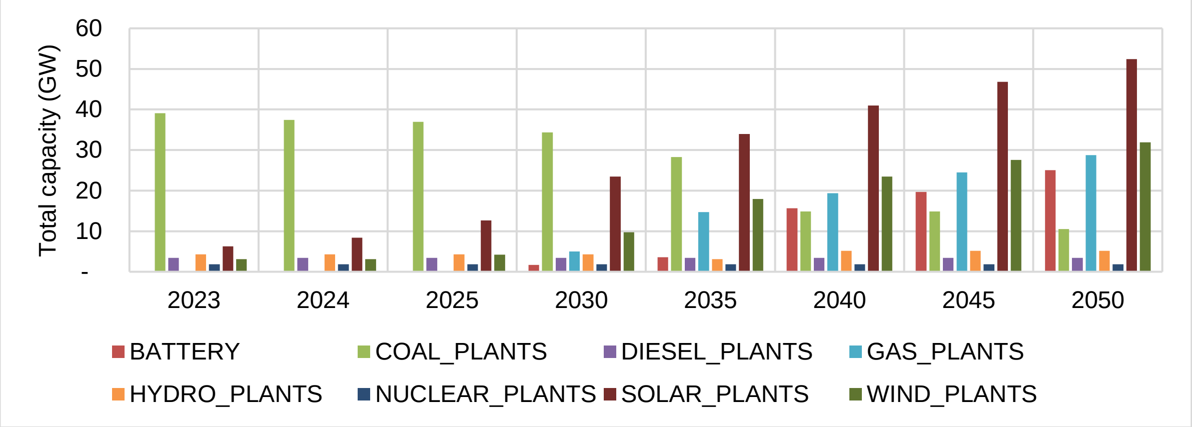

Figure 17: Scenario C Generation Capacity

Figure 18 presents a comparison of the operational generation capacity from each scenario in 2050. The overall trends are as expected given the underlying assumptions per scenario, which is:

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

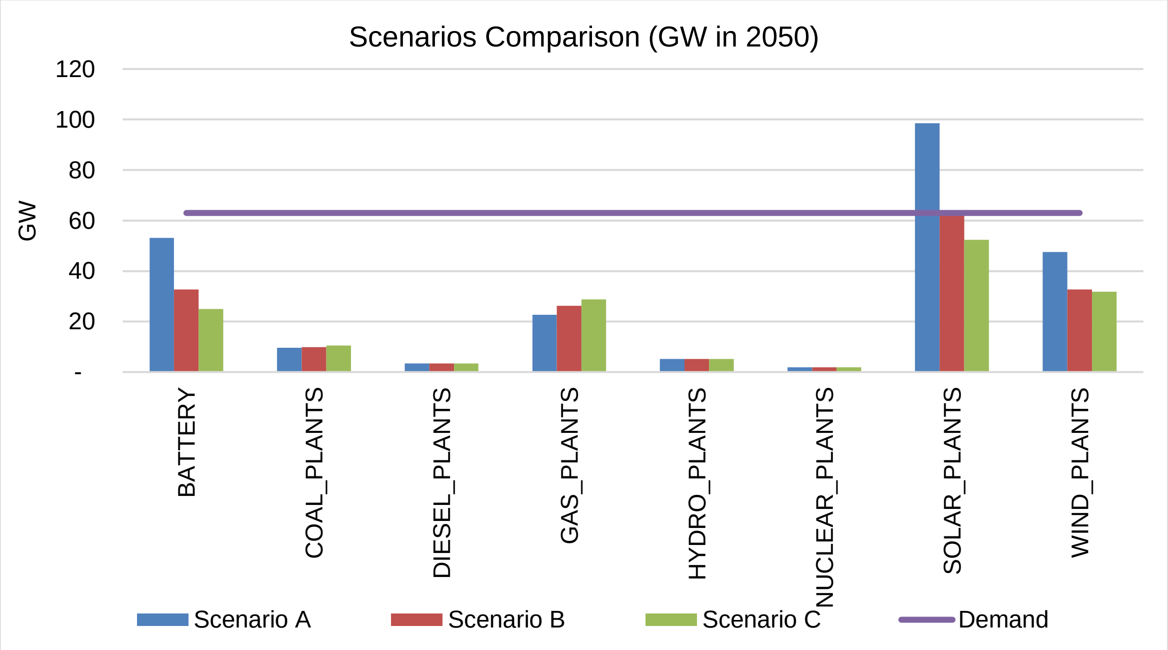

Figure 18: Total Operational Capacity per Scenario

Figure 19 presents a comparison of the average annual build rate of new 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 then Scenario C.

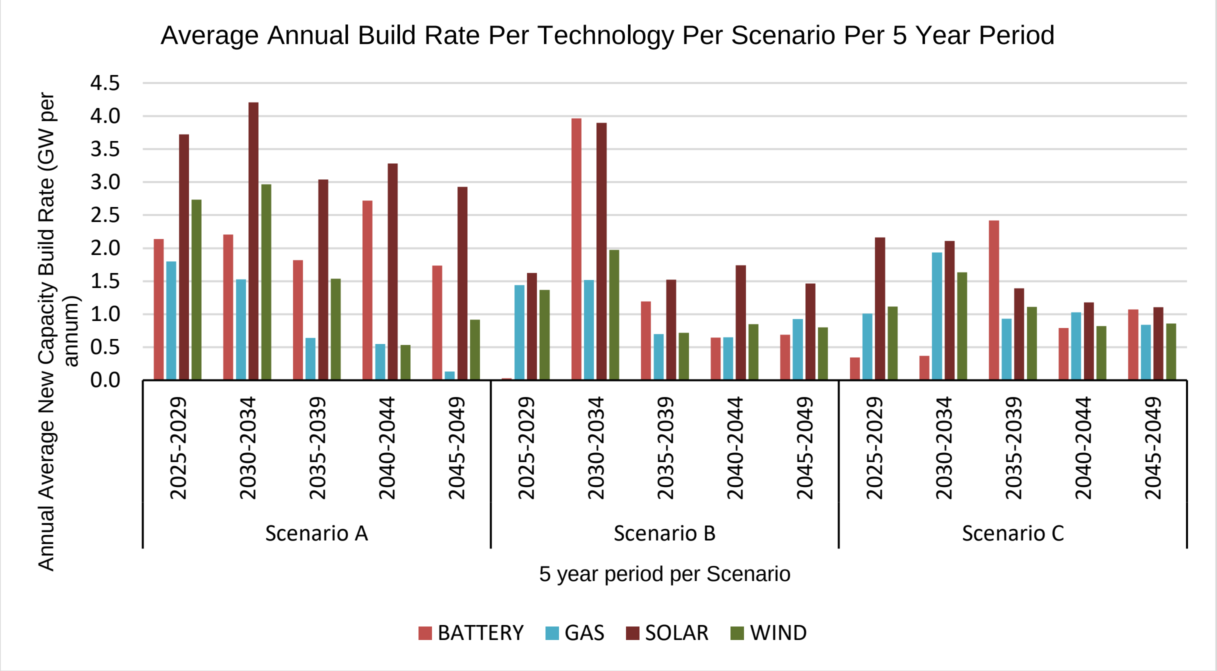

Figure 19: Average Annual New Generation Build Rate per Scenario

4.4.2 Dispatch and Energy Mix

Scenario A energy mix is shown in Figure 20.

In 2030, the demand is 261 TWh, with coal contributing 40% (104 TWh) as it remains a significant part of the mix. Gas generation is minimal at 5% (12 TWh), while nuclear and hydro 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 undergoes a significant transformation, with coal declining to 10% (32 TWh) as older plants retire. 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 grows to 40% (136 TWh). The shift toward renewables is accompanied by a substantial increase in battery storage, which reaches 81 TWh, helping to balance intermittent generation.

By 2050, the transition to renewables is nearly complete. Coal (retrofitted with CCS) shrinks further to 9% (40 TWh), gas capacity increases to act as backup to 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, playing a key role in system stability and energy shifting.

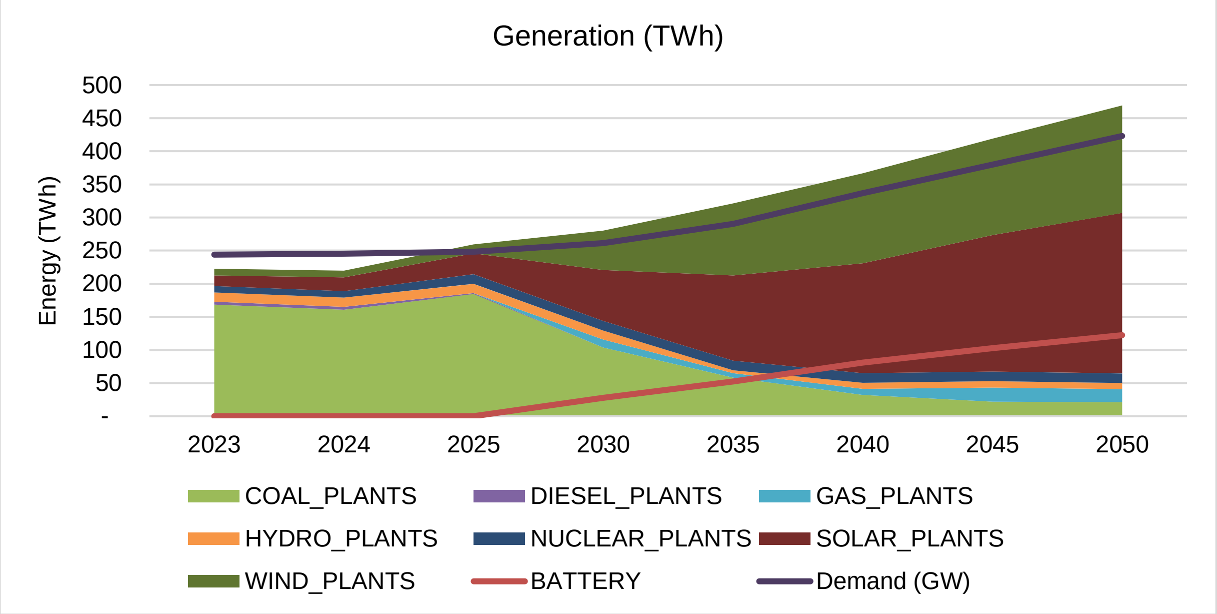

Figure 20: Scenario A Energy Mix

Scenario A’s dispatch profile for 2050 is shown in Figure 21. The dispatch profile is characterised by a high penetration of VRE sources. Coal and nuclear generation are operated with a consistent load factor. VRE is supplemented by gas-fired generation and energy storage (BESS and potentially pumped hydro) to manage intermittency. The dispatch profile exhibits pronounced diurnal patterns, with solar PV peaking during daylight hours and wind contributing variably throughout the day. BESS is primarily charged from excess VRE during the day and generally discharged during the evenings. Even with BESS, 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.

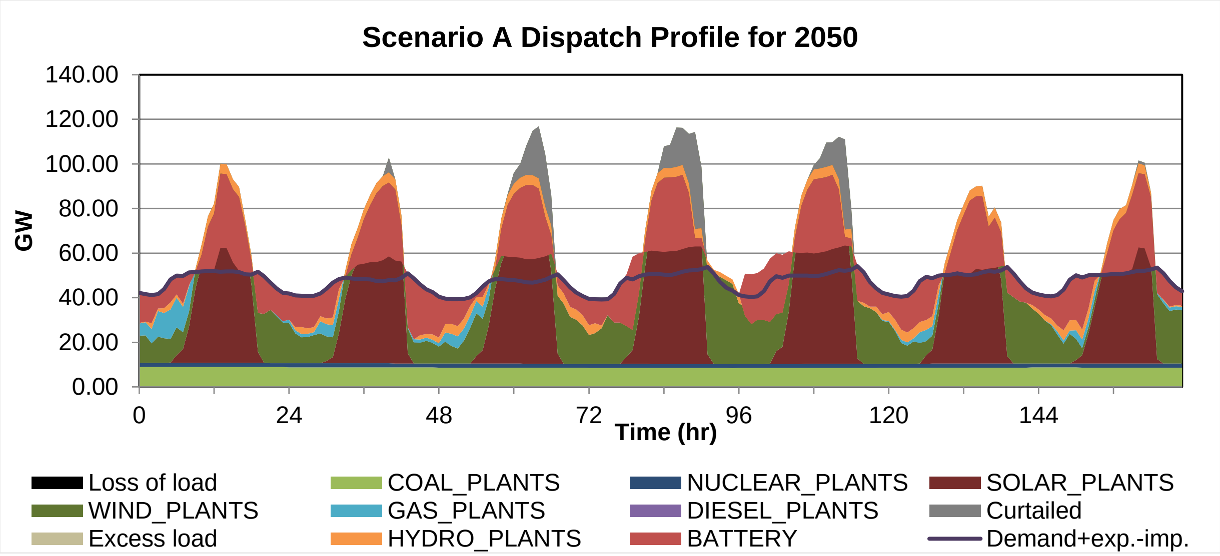

Figure 21 Scenario A Dispatch Profile

Scenario B energy mix in 2050 is shown in Figure 22.

In 2030, Scenario B maintains a stronger reliance on fossil fuels, with coal generation at 61% (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 retirements 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, helping to support renewable integration.

By 2050, Scenario B establishes a more balanced but fossil-fuel-inclusive mix. Coal generation (retrofitted with CCS) holds at 14% (61 TWh), gas expands 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.

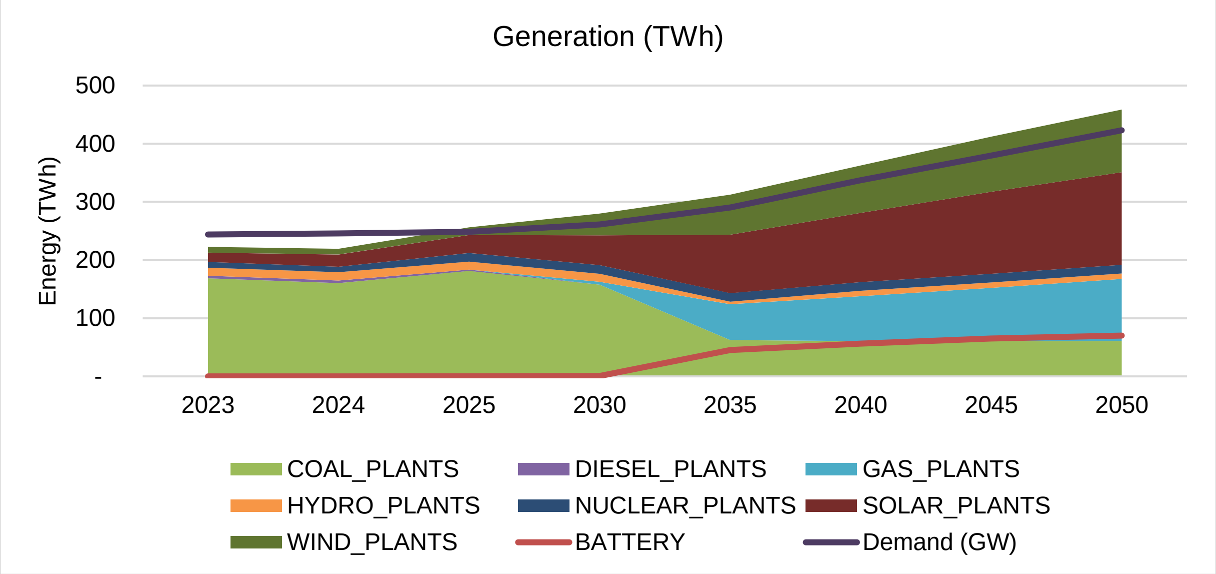

Figure 22: **Scenario B Energy Mix**

Scenario B's dispatch profile for 2050 is shown in Figure 23. 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 BESS and gas managing variability of VRE. Key differences from Scenario A are the more prominent dispatch of gas (due to lower gas price and less stringent carbon budget) and lower VRE curtailment (approximately 3.8% estimated using FlexTool) due to lower VRE capacity vs. demand.

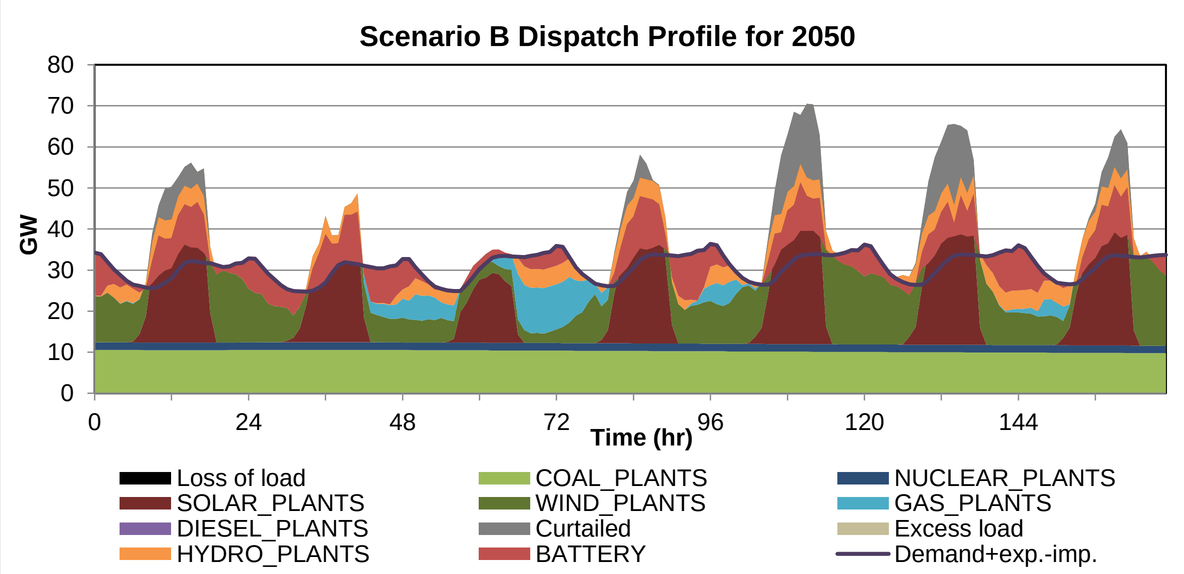

Figure 23: Scenario B Dispatch Profile

Scenario C energy mix is shown in Figure 24.

In 2030, Scenario C retains the highest share of coal generation at 61% (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 generation mix remains fossil fuel-heavy compared to the other scenarios. Coal declines to 27% (90 TWh), but gas expands significantly to 17% (57 TWh), providing a larger role in 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 at 46 TWh, supporting 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. Although renewables expand, they do not reach the same dominance as in Scenario A, with solar providing 30% (129 TWh) and wind contributing 25% (105 TWh). Battery storage reaches 55 TWh, helping to manage variability but not eliminating the need for gas reliance.

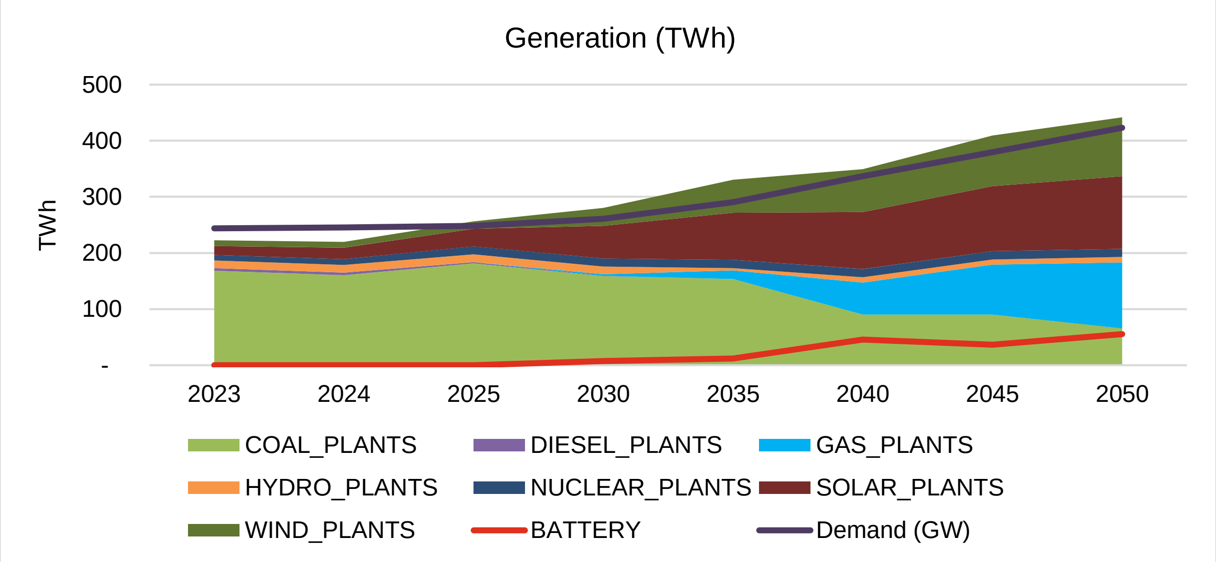

Figure 24: Scenario C Energy Mix

Scenario C's dispatch profile for 2050 is shown in Figure 25. The dispatch profile reflects a similar result to Scenarios A and B, with coal and nuclear dispatched at consistent load factors, significant diurnal patterns caused by VRE (although less pronounced than Scenarios A and B), and BESS and gas managing variability of VRE. Scenario C has the most prominent dispatch of gas (due to lower gas price and no carbon budget) and lowest VRE curtailment (approximately 0.3% estimated using FlexTool) due to lower VRE capacity vs. demand.

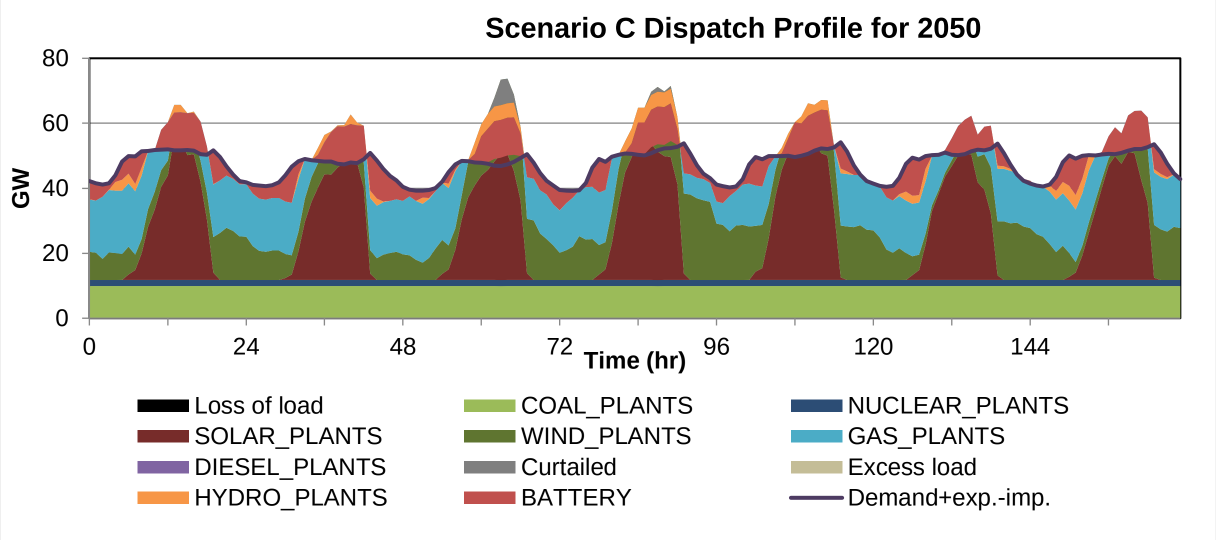

Figure 25: Scenario C Dispatch Profile

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 in the red lines connecting the supply. 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 Northern Cape to Gauteng via North West and Hydra Central to Gauteng via 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.

Scenario A, being the most aggressive decarbonisation 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 variable renewable energy 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 26 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 variable renewable energy in the system after coal decommissioning accelerates. This is illustrated in Figure 27 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 relatively less renewable energy projects and thus less generation capacity is built in the Hydra Central supply areas which results in relatively less transmission capacity being required between Hydra Central to Free State. This is depicted by the orange line in Figure 28 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

Start	End	Corridor Length (km)	Transmission Corridor Capacity (MW)		
			Scenario A	**Scenario B**	**Scenario C**
NC	FS	682	15 753	11 722	5 271
Total Capacity			**206 604**	**193 210**	**187 056**

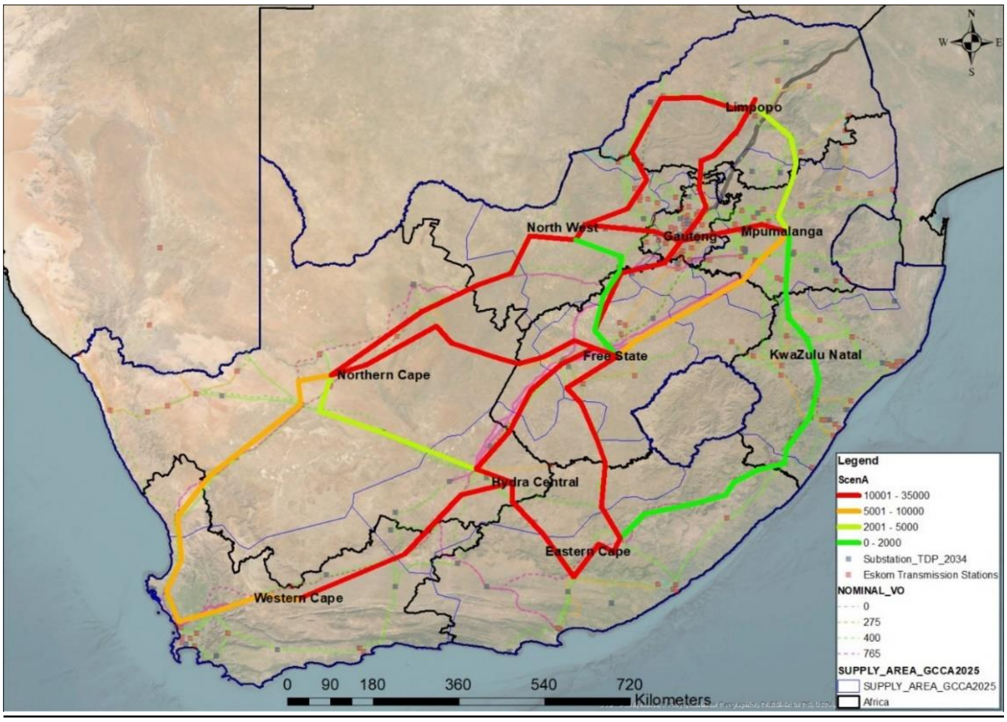

Figure 26: Scenario A Corridor Flows

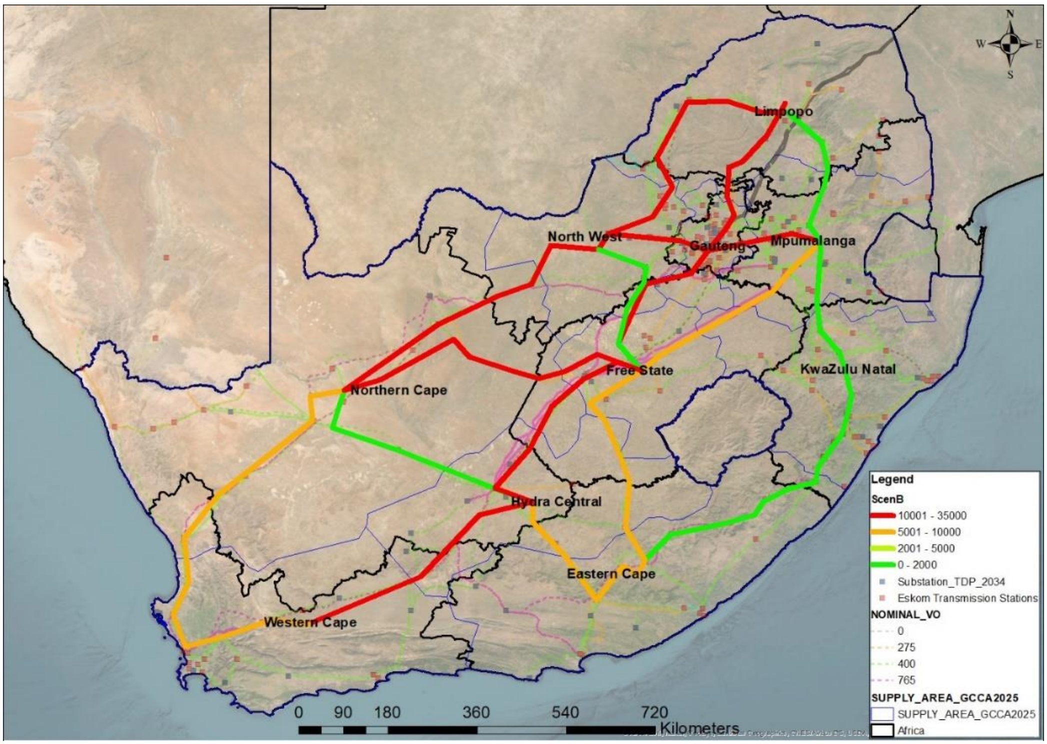

Figure 27: Scenario B Corridor Flows

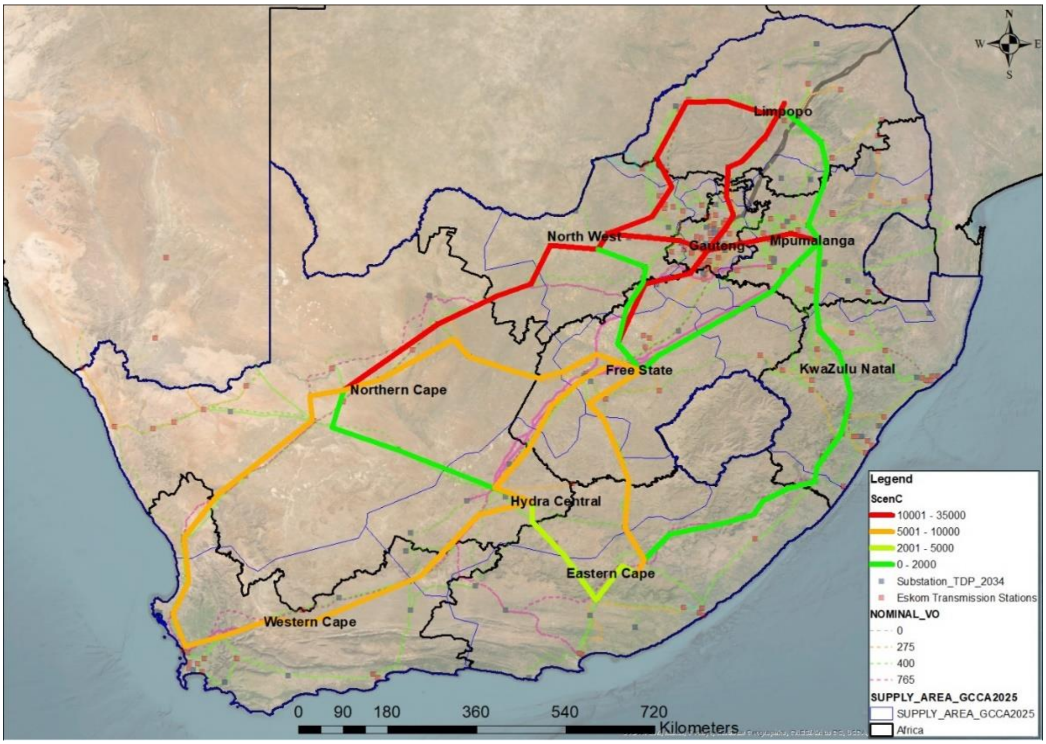

Figure 28: Scenario C Corridor Flows

4.4.4 CO_2 Emissions

Error! Reference source not found. illustrates the annual CO_2 emissions across the model period for S cenarios A, B, and C.

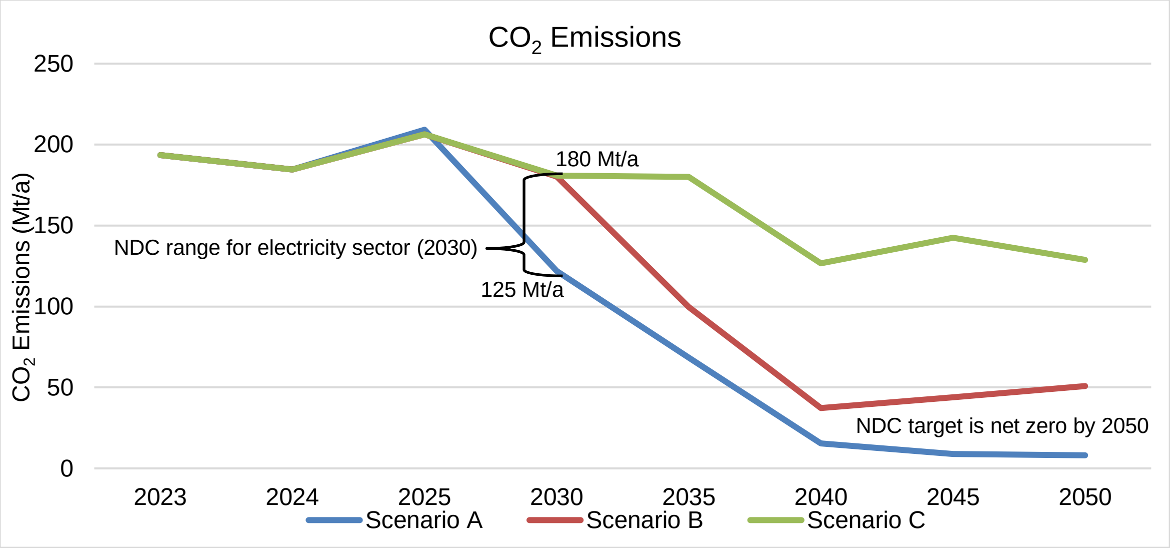

Figure 29: CO2 Emissions per Scenario

Scenario A results in **2.1 Gt of CO_2 emissions** from 2023 to 2050, slightly exceeding the original target of 2.0 Gt. Coal capacity is phased out quickly between 2025 and 2040. By 2040, Medupi, Kusile and Majuba power stations are retrofitted with CCS, while Kendal, Lethabo and Matimba power stations 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 30Figure 30.

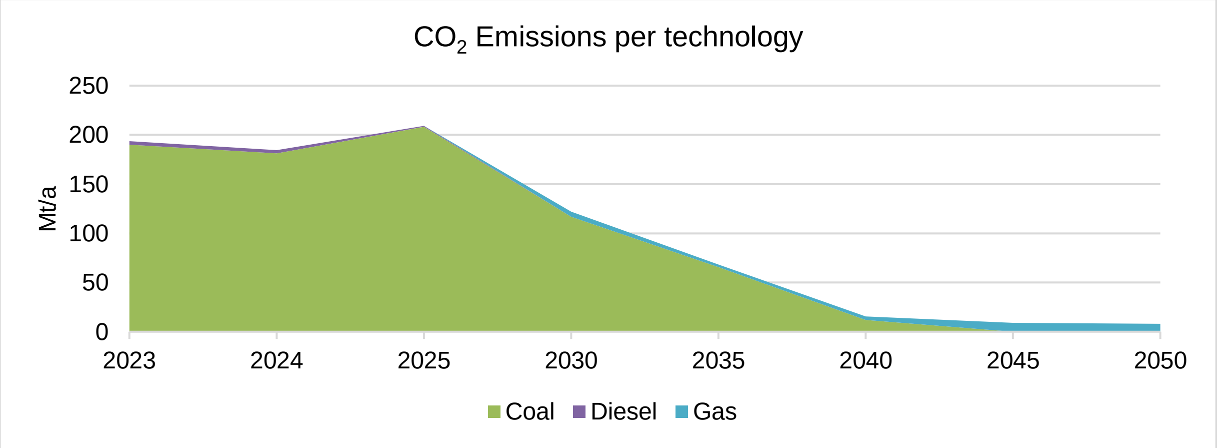

Figure 30: Scenario A CO_2 Emissions per Technology

Scenario B results in **3.1 Gt of CO_2 emissions** from 2023 to 2050, against a target of 3.0 Gt. This scenario adopts a more gradual decarbonisation 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 life (2040). As illustrated by the blue area in Figure 31Figure 31, the relatively higher contribution of gas generation beyond 2040, results in higher emissions between 2040 and 2050 compared to Scenario A.

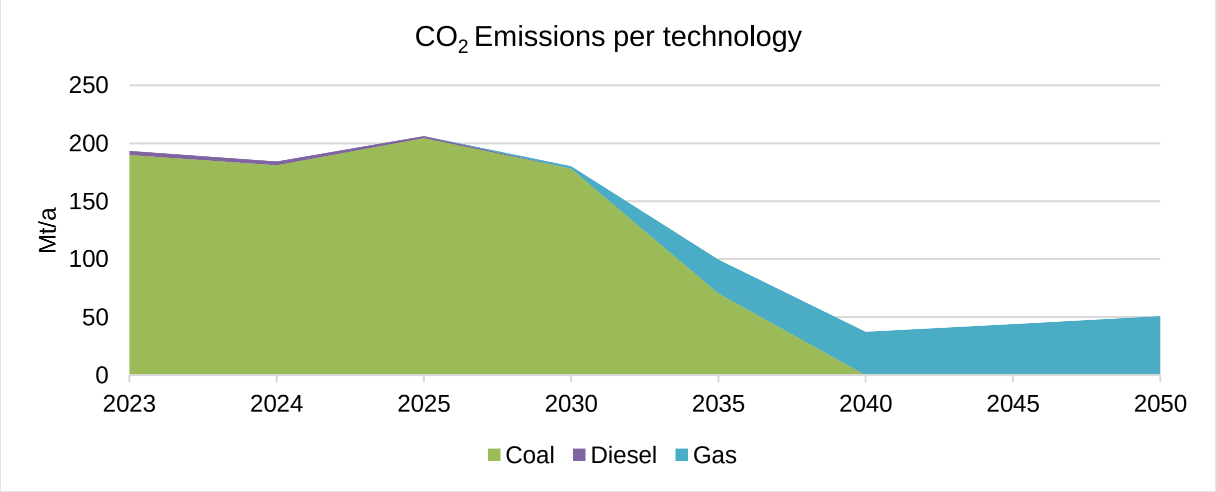

Figure 31: Scenario B CO_2 Emissions per Technology

Scenario C had no CO_2 constraint and results in **4.5 Gt of CO_2 emissions** from 2023 to 2050. With an extended life of the coal fleet (i.e., delayed decommissioning schedule), 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 32 compared to Scenario A and B.

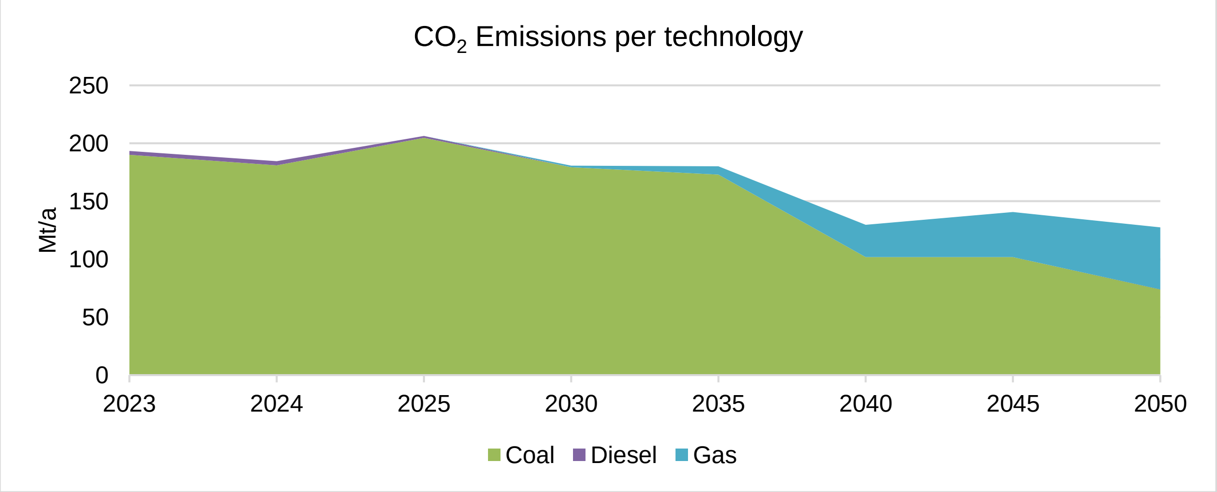

Figure 32: Scenario C CO_2 Emissions per Technology

4.4.5 Generation Costs

All costs in this section, unless stated otherwise, have been discounted to 2024 based on a discount rate of 8%, and while the generation mix was optimised based on carbon tax, the carbon tax costs are excluded from the costs presented here.

It is also important to note throughout this section that the cost parameters differ between the three scenarios, e.g., optimistic learning rates adopted in Scenario A / pessimistic learning rates in Scenario C, lower coal and gas prices in Scenario A / higher coal and gas prices in Scenario C, higher carbon tax in Scenario A / lower carbon tax in Scenario C, high Capex premium (as proxy for high cost of capital) on fossil fuel technologies in Scenario A / no Capex premium on fossil fuel technologies in Scenario C.

Scenario A requires the highest capital expenditure (R 1 651 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 (R 3 203 billion), due to the relatively low variable cost (R 727 billion). The low variable cost is a result of the system's 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 33. Fixed costs are larger than other scenarios (R 825 billion) despite optimistic technology learning rates for VRE and BESS, due to the much larger generation capacity.

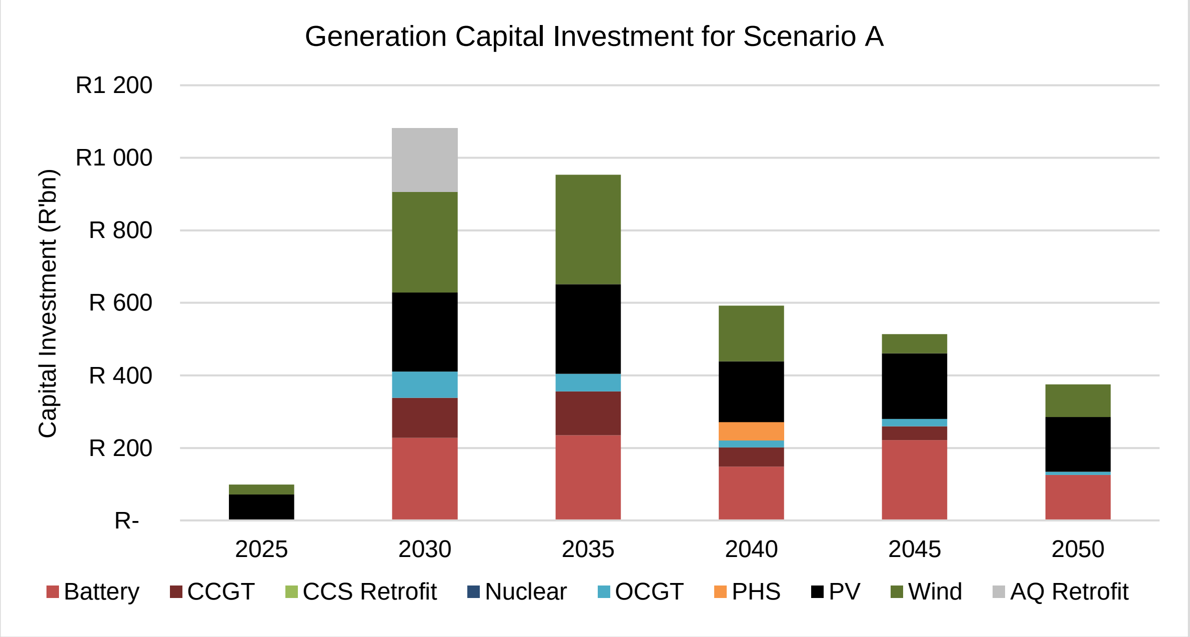

Figure 33: **Scenario A Generation Capital Investment (not discounted)**

Figure 34 below illustrates generation capital cost for Scenario B**.**

Scenario B has a significantly lower capital expenditure (R 1 229 billion) than Scenario A, but higher variable costs (R 1 520 billion), leading to a higher total system cost of R 3 395 billion. This is the result of a more gradual transition away from coal, later implementation of AQ retrofits (2035) and CCS (2040), and less new 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 proxy for cost of capital) on fossil fuel technologies compared to Scenario A, more gas capacity is built, further increasing variable costs.

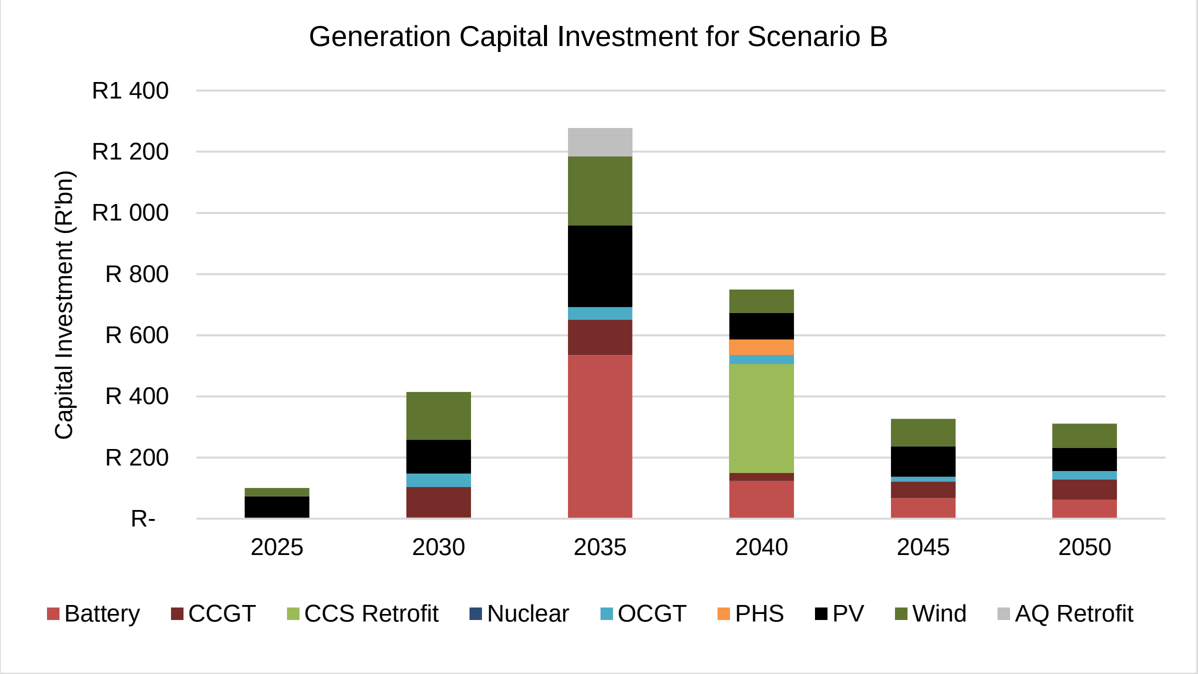

Figure 34: **Scenario B Capital Investment (not discounted)**

Scenario C requires a capital expenditure of R 1 446 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 capital expenditure to be higher than Scenario B as illustrated in Figure 35. The total system cost (R 3 935 billion) is the highest among the scenarios due to significantly higher variable costs (R 1 814 billion). This is attributed to a prolonged dependence on coal generation, higher dependence on gas, combined with higher 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 (R 675 billion) is comparable to other scenarios, because of less new capacity (which reduces fixed costs) being offset by pessimistic technology learning rates (which increases fixed costs).

A comparison of the capital investments for the three scenarios is illustrated in Figure 36 below.

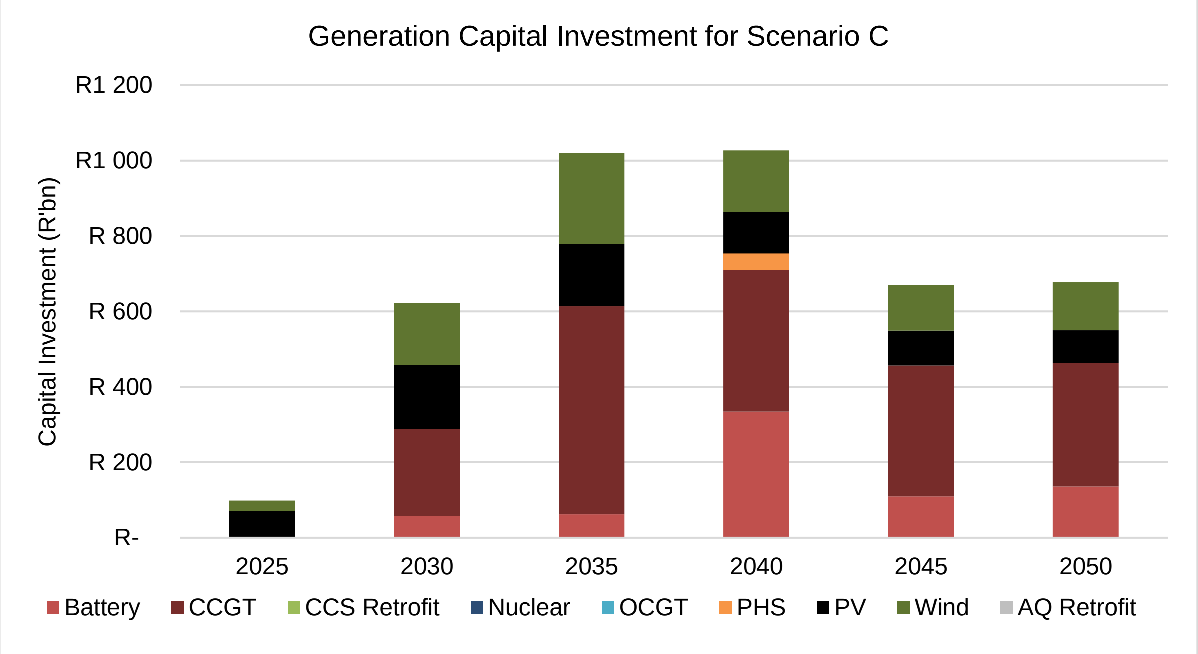

Figure 35: Scenario C Capital Investment (not discounted)

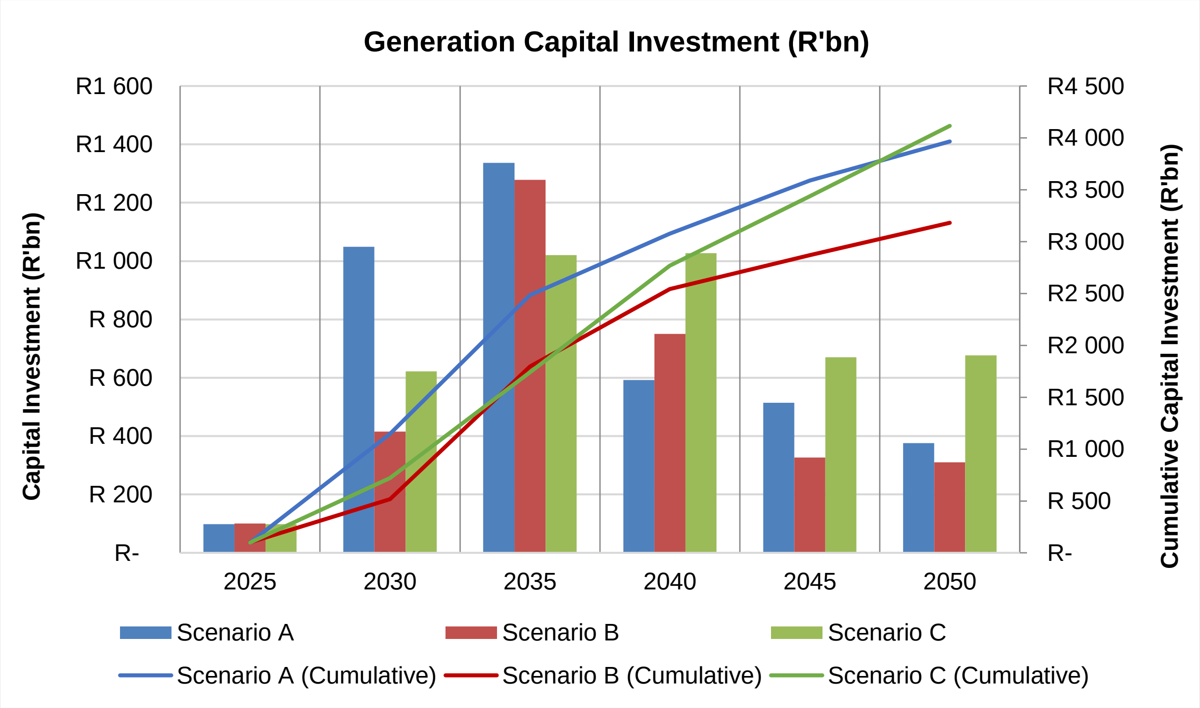

Figure 36: Generation Capital Investment per Scenario (not discounted)

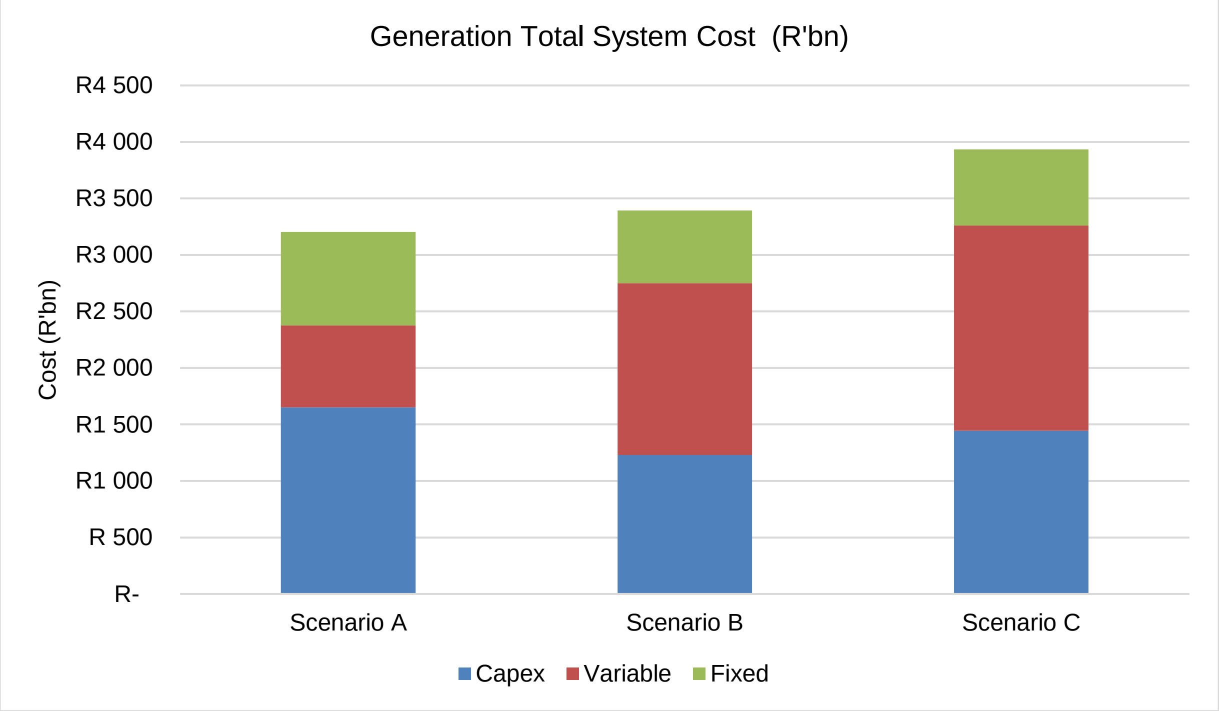

Figure 37: Generation Total System Cost per Scenario (Discounted at 8% to 2024)

Generation costs can be summarised with the following comparative insights:

- **Capex Trends**: Scenario A incurs the highest Capex costs due to its aggressive build-out of VRE and BESS, while Scenario B and C opt for more incremental transitions, leading to lower capital expenditures. The pessimistic technology learning rates adopted for Scenario C mean that it requires higher Capex costs 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 and higher coal and gas prices, while Scenario A benefits from lower fuel prices and a higher penetration of renewable energy.
- **Fixed Costs**: Are similar for all scenarios as the quantum of generation capacity (highest in Scenario A and lowest in Scenario C) is offset against the differing technology learning rates (optimistic in Scenario A and pessimistic in Scenario C).
- **Total Cost Considerations**: As illustrated in Figure 37, Scenario A, despite its high Capex, achieves the lowest total system cost due to reduced reliance on fossil fuel generation and lower fuel prices. Scenario C, while delaying upfront investments, incurs the highest long-term cost due to continued fossil fuel generation, higher fuel prices and pessimistic technology learning rates.

It should be noted that the generation cost results presented in this section reflect system-level modelling outcomes based on technology-specific capital and operating cost assumptions, and do not fully incorporate the cost of capital[16] 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, including for refurbishment and AQ compliance retrofit costs, may come at a premium 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 centers. Transmission corridor capacities vary across scenarios, reflecting differences in renewable energy integration and fossil fuel reliance, as discussed in Section 4.4.3.

It is important to clarify that the grid investment costs presented in this study include both transmission and distribution infrastructure. The Transmission Development Plan (TDP) produced by Eskom focuses exclusively on the transmission network, which is now operated by the National Transmission Company South Africa (NTCSA) following the recent unbundling of Eskom. In contrast, this study also accounts for the significant investment required in distribution collector networks to integrate variable renewable energy (VRE) into the grid. These distribution investments are particularly substantial in scenarios with large-scale renewable deployment and currently do not have a formal equivalent planning document like 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 38 provides a comparison and breakdown of the total grid expansion costs required by 2050, per Scenario. The total grid expansion costs differ significantly across the three scenarios. Scenario A incurs the highest investment, at R 922 billion (not discounted), due to the extensive substation and distribution network expansions required for large-scale renewable integration. Scenario B follows with a cost of R 630 billion, reflecting the smaller capacity of new generation compared to Scenario A. Scenario C has the lowest grid investment at R 555 billion, as it relies more on the existing transmission infrastructure rather than integrating such a large capacity of new variable renewable energy sources.

It is evident from Figure 38 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 is greater than the cost of all new transmission infrastructure (backbones, collection lines, and substation), comprising

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[16] *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.*

53% of the total grid cost. Distribution collector networks in Scenario B and Scenario C comprise 47% and 43% of the total grid cost, respectively.

Comparing the total grid cost against total system cost (i.e., where total system cost is the sum of total grid costs and total generation costs), total grid costs comprise 19%, 17% and 12% of the total system cost for Scenarios A, B and C, respectively (comparing based on non-discounted costs). The total grid costs as a proportion of total system cost are the highest for Scenario A due to the large impact of the distribution collector network costs required for the large quantum of new renewable energy and BESS capacity.

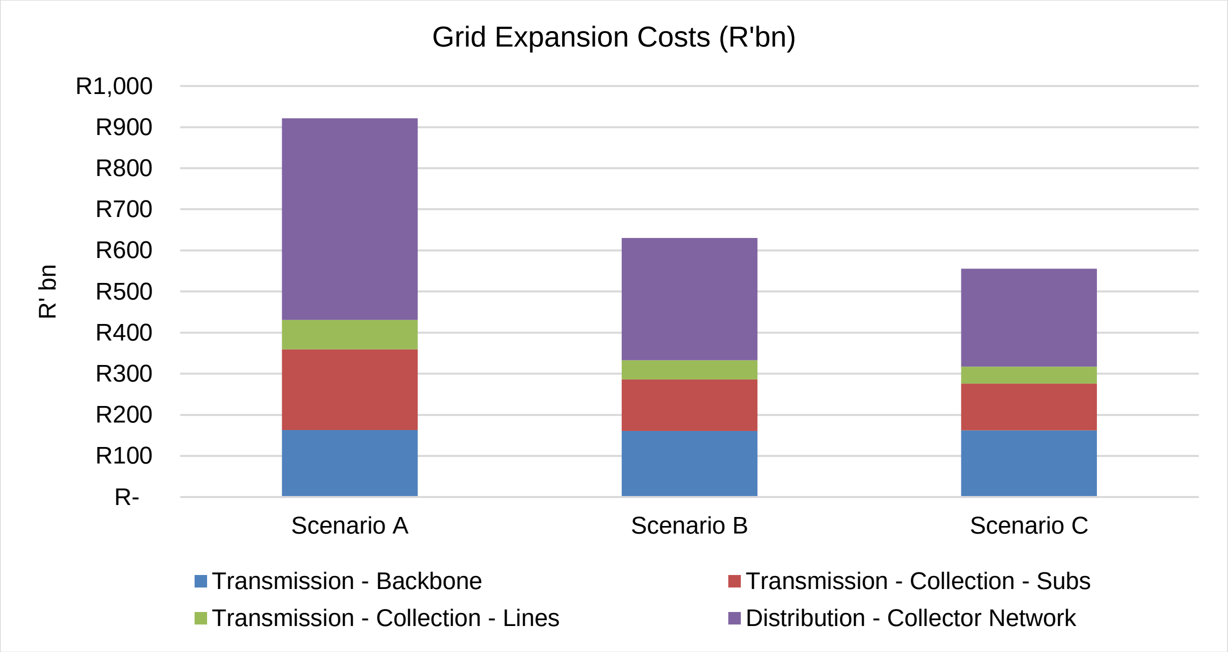

Figure 38: Total Grid Cost per Scenario (not discounted)

4.4.7 Summary

Table 15: Results Summary includes a side-by-side comparison of the key input assumptions and output results (capacity and cost) per Scenario.

Figure 39, Figure 40 and Figure 41 provide a one-page summary of the key results from Scenarios A, B and C, respectively.

Table 15: Results Summary

Area	Model parameter / descriptor	Scenario A Green Industrialisation	Scenario B Market Forces	Scenario C Business-as-usual
INPUTS				
Policy & regulations	Carbon emissions target	2.0 $GtCO_2e$	3.0 $GtCO_2e$	No limit
	Adherence to air quality standards	Mandated by 2030	Mandated by 2035	Not mandated
	Carbon Border Adjustment Mechanism (CBAM) and other export market regulations[17]	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

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

Area	Model parameter / descriptor	Scenario A Green Industrialisation	Scenario B Market Forces	Scenario C Business-as-usual
Generation	Coal fleet decommissioning	Pathway 1 (IRP 2019, with adjustments) (University of Pretoria General Equilibrium Model, December 2023)	Pathway 1 (IRP 2019, with adjustments) (University of Pretoria General Equilibrium Model, December 2023)	Pathway 2 (Delayed decommissioning timeline relative to pathway 1) (University of Pretoria General Equilibrium Model, December 2023)
	Coal fleet EAF	High 65% from 2023 to 70% by 2035, 70% to end, except Medupi and Kusile which are 73% from 2025	Medium 65% throughout, except Medupi and Kusile which are 73% from 2025	Low 60% throughout, except 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 / learning rates	Optimistic (Likely scenario from Meridian, Review of the Draft IRP 2023, March 2024)	Moderate (Base Case scenario from Meridian, Review of the Draft IRP 2023, March 2024)	Pessimistic (Stress scenario from Meridian, Review of the Draft IRP 2023, March 2024)
Fuel Prices	Coal and natural gas	Low (NZE scenario from IEA WEO, 2024)	Moderate (APS scenario from IEA WEO, 2024)	High (STEPS scenario from IEA WEO, 2024)

Area	Model parameter / descriptor	Scenario A Green Industrialisation	Scenario B Market Forces	Scenario C Business-as-usual
Capital	Size of market / funding[18]	Limited local and international funding available for zero carbon generation options. Finance for carbon intensive generation is even more expensive.	Local and international funding available for zero carbon generation options. Finance for carbon intensive generation is more expensive.	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).
	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				
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

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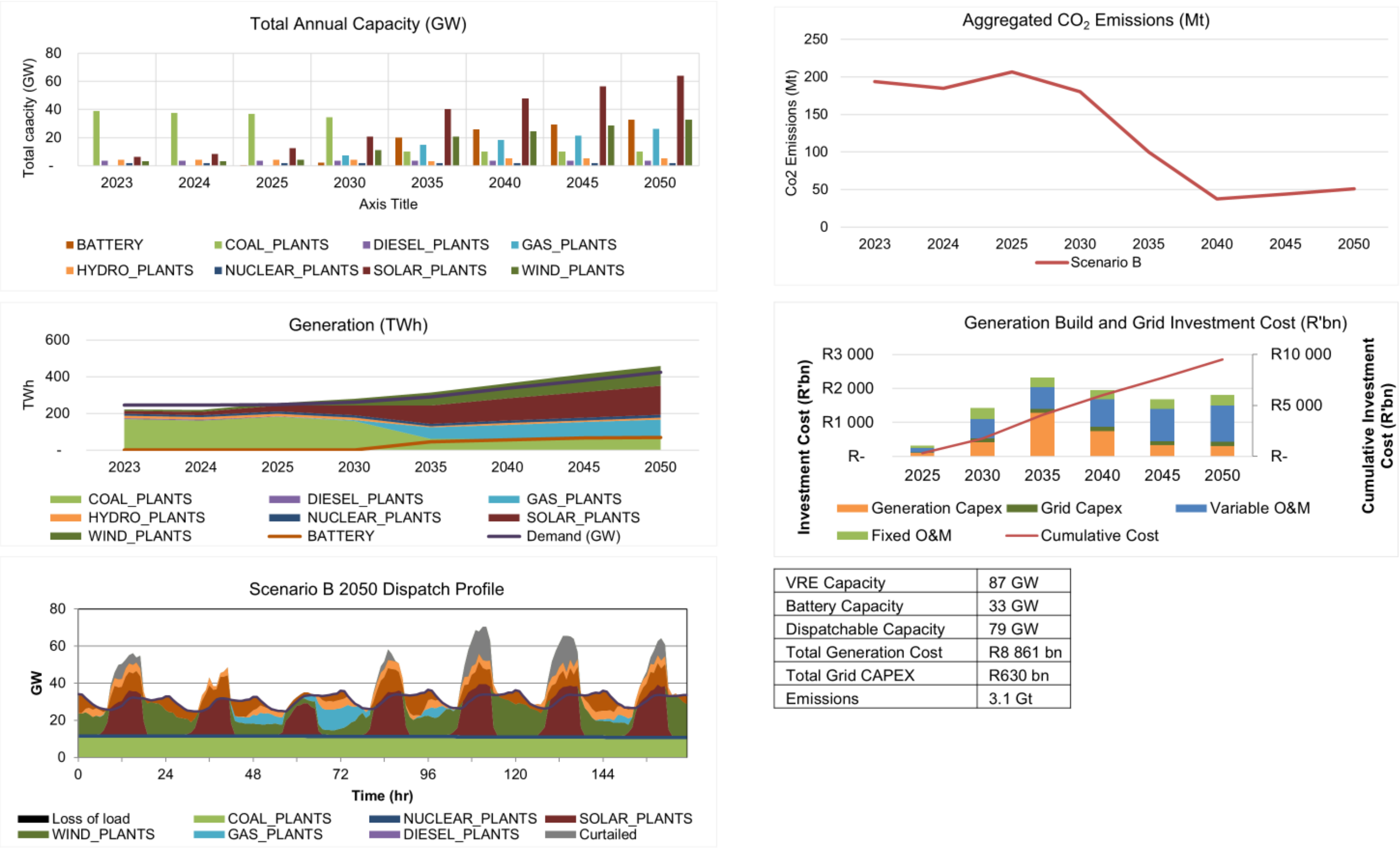
[18] *Descriptor of the external environment, as opposed to a modelling input.*

Area	Model parameter / descriptor	Scenario A Green Industrialisation	Scenario B Market Forces	Scenario C Business-as-usual
	2040	Solar: 67 Wind: 40 BESS: 31 Gas: 20 Coal: 14 (incl. 10GW 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	Generation Cost	R 3 203 262 million	R 3 394 635 million	R 3 935 063 million

Area	Model parameter / descriptor	Scenario A Green Industrialisation	Scenario B Market Forces	Scenario C Business-as-usual
(Discounted to 2024 at 8%)	Grid Cost	R 383 234 million	R 262 023 million	R 230 853 million
	Total Cost (Difference from A)	R 3 586 496 million (0%)	R 3 656 658 million (+2%)	R 4 165 916 million (+16%)

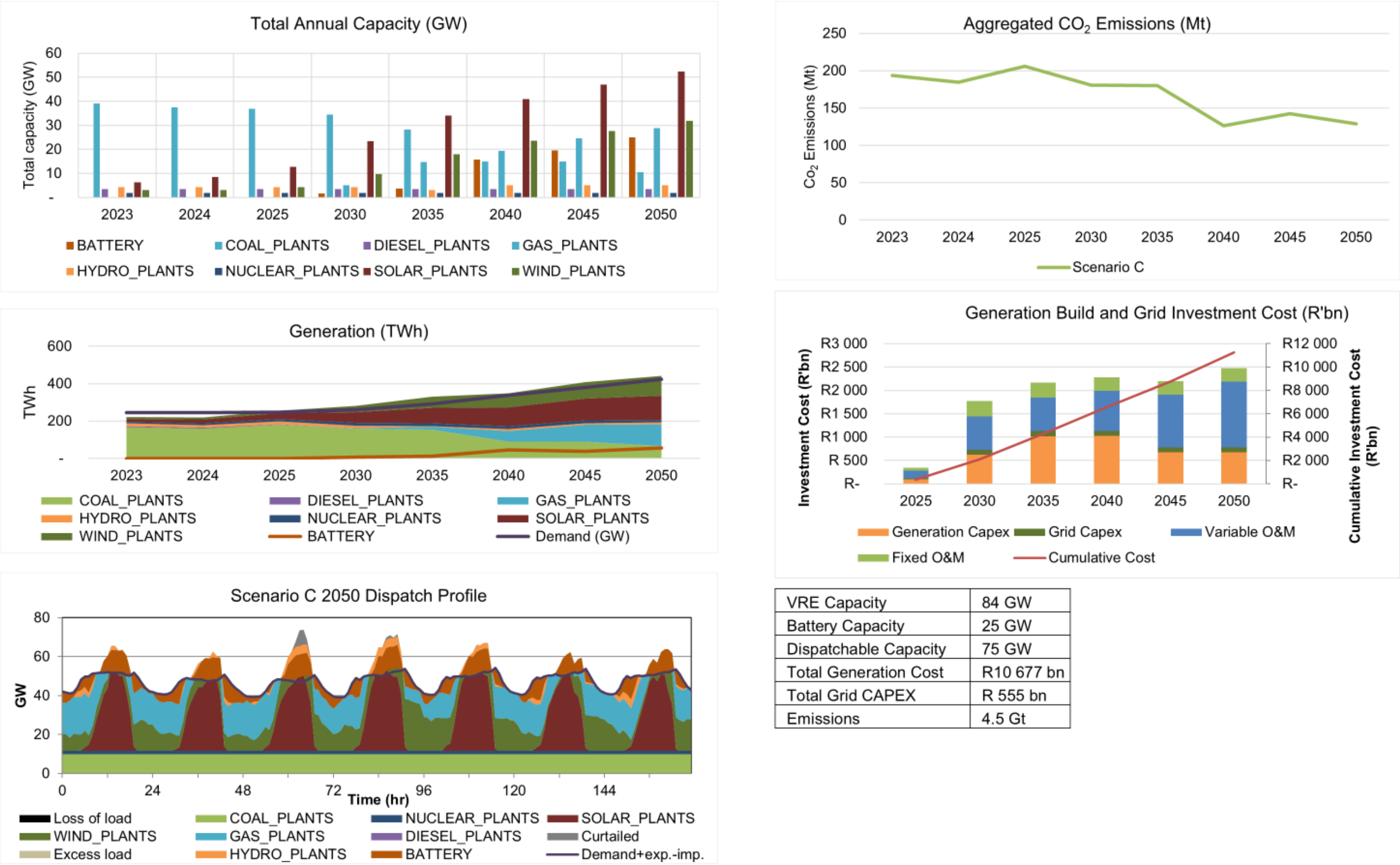
VRE Capacity	146 GW
Battery Capacity	53 GW
Dispatchable Capacity	97 GW
Total Generation Cost	R7 549 bn
Total Grid CAPEX	R922 bn
Emissions	2.1 Gt

Figure 39: Consolidated Summary for Scenario A (costs 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 40:Consolidated Summary for Scenario B (costs 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 41:Consolidated Summary for Scenario C (costs not discounted)

4.5 Sensitivity Analyses

4.5.1 Methodology

The energy modelling sensitivity analyses explore how key policy, economic, and technical uncertainties influence the findings presented in this study. By varying key input parameters, such as fuel prices, technology costs, carbon taxation, and coal fleet performance (amongst others), the analysis assesses the robustness of the capacity expansion, dispatch profile, and cost structure under different conditions. Each sensitivity 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, with input assumptions that lie in between those used for 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 optimises the generation mix based on least-cost principles while adhering to emissions constraints, fuel price fluctuations, technology learning rates, etc.

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 IRP 2023 Ref 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 Eskom coal fleet (except 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? (source: Meridian, Review of the IRP 2023)
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 USD104/tonne CO_2 to USD68/tonne CO_2 in 2050
14	Increased Carbon Tax	What happens if the Carbon Tax is increased? From USD104/tonne CO_2 to USD188/tonne CO_2 in 2050

4.5.2 Sensitivity Results

The sensitivity analyses reveal distinct trends across various groups of parameters relative to the base case in Scenario B. The differences in cost breakdowns are depicted in Figure 43 shows the full range of total generation costs for all scenarios and sensitivities cases. Table 17 summarises the differences in capacity per technology for each sensitivity, and Table 18 provides a comparison of generation costs, including carbon tax costs.

The "Medium TDP Demand" scenario, which slightly reduces the 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 premium on 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 toward more renewables and storage, while a much larger 30% premium is required before the model chooses to deploy new nuclear capacity.

A lower Energy Availability Factor (EAF) for the coal fleet forces the system to compensate by dispatching more gas, but only for a relatively short period (around 2030), after which time most of the coal fleet is de-commissioned. Inversely, delaying coal decommissioning and forcing coal plants to remain online until their end of life, reduces near-term renewable and gas investments but requires a much larger reduction in CO_2 emissions in the long term to adhere to the 3.0 $GtCO_2$ emissions budget. Similarly, if air quality (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 1.5x to 2x the current expected costs for the model to not deploy CCS and instead decommission these plants and replace the generation with other technologies.

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 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 much the same as Scenario B. Higher gas prices, on the other hand, encourage a shift toward renewables and storage, albeit at a higher capital cost and higher total system cost.

Adjustments to carbon tax levels have an expected impact of shifting new capacity investments between fossil fuel and 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.

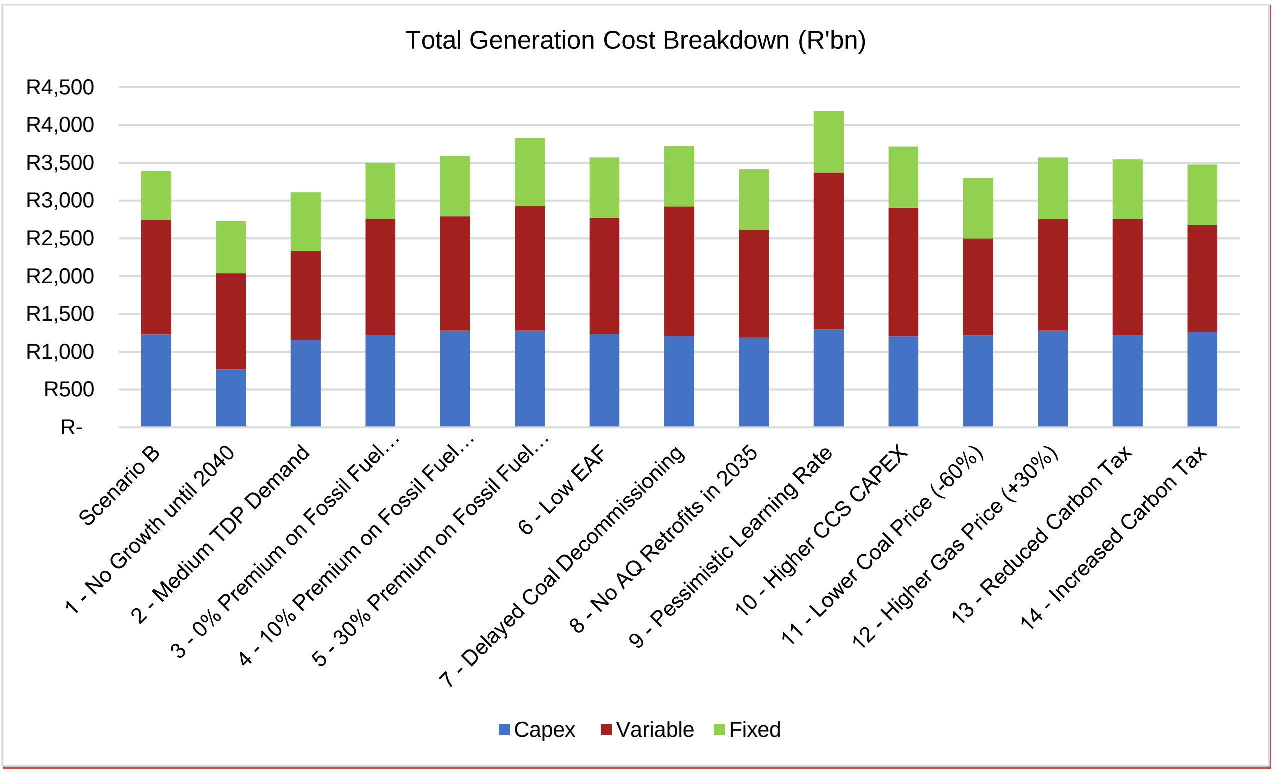


Figure 42: Total Generation Cost Breakdown per Sensitivity (Discounted, R’ billion)

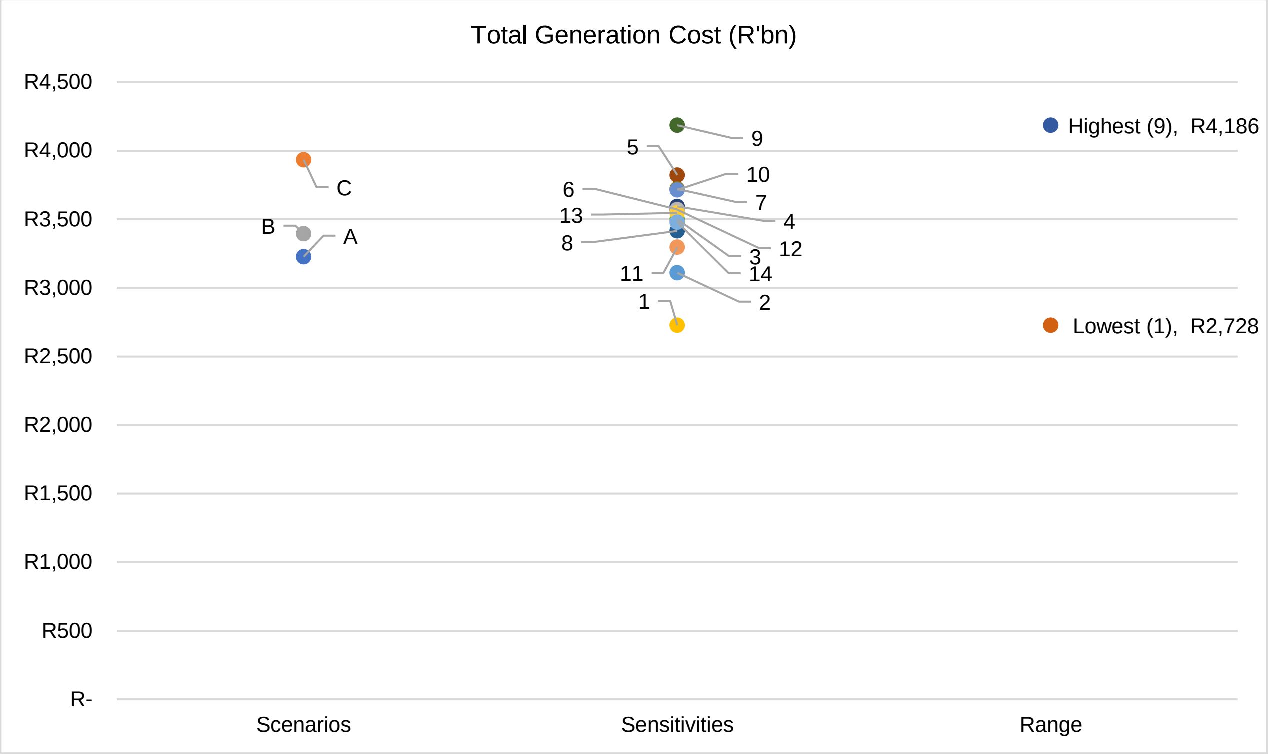


Figure 43: Total Generation Cost for All Sensitivities and Scenarios (R’ billion, Discounted)

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, 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.

Sensitivity	Description	Generation Capacity in GW by 2050							Notes
		Solar	Wind	BESS	Coal	CCS	Gas	Nuclear	
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.
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 billions, Total 2025 to 2050, Discounted at 8% to 2024)

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
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

Sensitivity	Description	Capex	Variable	Fixed	Total Cost	Total Cost + CO_2 Tax
14	Increased Carbon Tax	R 34	-R 105	R 156	R 85	R 326

4.6 Results discussion

4.6.1 Expansion of Variable Renewable Energy

In all Scenarios and Sensitivities the largest component of new generation capacity is the variable renewable energy (VRE) technologies, comprising solar PV and wind i.e., this result occurs irrespective of the range of CO_2 budget constraints (including no constraint), technology learning rates, level of carbon tax, level of coal and gas price, and level of Capex premium on fossil fuel technologies (as proxy for 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 i.e., 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, 2024). The IRP 2019 (as the last accepted IRP) sets a measurable target of an increase in renewable energy from the current state of about 10% to around 40% by 2030 with the intention to reduce the share of fossil fuels from 80% to about 50% out of a projected installed capacity of 78 GW, excluding distributed capacity in the total (EnergyGroup, 2024). This will be achieved through the new additional capacity of 14 GW of wind and 6 GW of solar PV, excluding already 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 PV, 6 GW of PV, 8 GW of wind, and 600 MW of CSP (DMRE, 2024a). Following on from the Draft IRP 2023, the DMRE released a Draft Integrated Resource Plan Stakeholder Workshop document in November 2024. The stakeholder workshop document expresses the incorporation of more renewables being established, particularly up to 2030. The Draft IRP 2024 Stakeholder Workshops document (referred to as the "Draft IRP 2024" document in the comparison tables in this report) also states that VRE will contribute an additional 27.4 GW to the national capacity by 2030. This would be attributable to 11.3 GW of rooftop PV, 7.8 GW of utility scale PV, and 7.2 GW of wind by 2030. The total build-out of VRE by 2050, as per the Draft IRP 2024 Stakeholder Workshops document, also expresses aggressive development of renewable energy, potentially contributing 127 GW to the national total by 2050. This would be due to 24.3 GW of PV and 76.4 GW of wind energy being added to the grid between 2031 and 2050 (DMRE, 2024b).

The 2024 South African Renewable Energy Grid Survey provides an overview of renewable energy projects which are still in development and will require grid access by 2032 (Eskom, 2024c). The survey is co-authored by the South African Photovoltaic Industry Association (SAPVIA), Eskom and the South African Wind Energy Association (SAWEA) and involves applicants providing information regarding their projects in development. Projects are split into type A, B and C categories.

Type A projects are at an advanced stage of development, 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 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 5 years if granted grid connection immediately. Type C projects are still at an early stage of development and are still in feasibility/prefeasibility stage. These projects should reach COD within 5-7 years. Table 19 shows the total capacity of PV and wind projects by the year 2030 and it 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 Review of the IRP 2023 in March 2024, providing an independent integrated resource planning analysis of the IRP 2023 (Meridian Economics, 2024). The study presents a range of scenarios reflecting different assumptions on 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. Under 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 rises further 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 projected installed VRE capacities by 2030 from the IRP 2019, Draft IRP 2023, Draft IRP 2024 Stakeholders Workshop document (Draft IRP 2024), 2024 South African Renewable Energy Grid Survey (Eskom, 2024c), and this study.

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

Energy Source	IRP 2019	Draft IRP 2023	Draft IRP 2024	Meridian[19]	Grid Survey[20] (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
PV	8	6	19	CO2040: 24 LRL: 23 BC: 21	45	A: 31 B: 21 C: 23
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: IRP 2019 (DMRE), 2019; Draft IRP 2023 (DMRE), 2024a; Draft IRP 2024 (DMRE), 2024b; Meridian Economics, 2024; South African Renewable Energy Grid Survey (Eskom), 2024c

Scenario A from this study results in 22 GW more of total VRE capacity compared to Draft IRP 2024. Scenario A adopts more optimistic technology learning rates than the Draft IRP 2024, 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 Meridian’s Review of the IRP 2023, envisage a similar level of VRE capacity as Scenarios B and C from this study.

Notably, the 62 GW of Type A and B projects identified in the 2024 Grid Survey exceeds 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 that grid access is granted. This comparison suggests that Scenario A is well aligned with existing market interest and development activity, and that achieving its build-out targets is feasible if proactive grid planning and timely connection approvals are implemented.

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

[20] *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 5 years if granted grid connection immediately.*

4.6.1.2 Time Horizon: 2031 to 2050

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

Meridian Economics’ Review of the IRP 2023 report 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 understood through the REIPPPP and other reference data (Meridian Economics, 2024). Additionally, the Draft IRP 2023 does not account for future technology learning, inflating costs for new technologies compared to mature ones like coal, nuclear, and gas. The presentation of scenarios in the IRP does not provide costing for flue gas desulphurisation (i.e., air quality) retrofits or carbon capture and storage (CCS). Meridian Economics calls for significant revisions to the IRP 2023 to better align with South Africa's energy transition goals and economic realities, emphasising the need for a transparent and inclusive stakeholder engagement process. The analysis concludes that the plan is unrealistically constrained, with over-priced renewables facilitating a gas-heavy energy future, in discord with SDG 7.2 (Meridian Economics, 2024). The independent assessment of the IRP by Meridian also establishes various scenarios of which three have been selected for comparison with the results in this study.

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

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

Energy Source	Draft IRP 2024	Meridian[21]	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: Draft IRP 2024 (DMRE), 2024b; Meridian Economics, 2024

A comparison of variable renewable energy (VRE) capacity projections across this study, the Draft IRP 2024, and Meridian scenarios, summarised in Table 21, shows both broad similarities and notable differences in terms of total capacity as well as the technology split between wind and PV.

A key point of alignment across all modelling exercises is that VRE — comprising 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's scenarios (ranging from 84 GW to 147 GW across Scenarios A, B, and C) falls within the broader range defined by Meridian’s modelling outcomes (115 GW to 172 GW) and the Draft IRP 2024 projection (127 GW).

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

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

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

example, Meridian scenarios that favour higher wind capacity may reflect different treatment of wind resource availability and yield profiles across the country.

Despite these differences, it is important to emphasise that all models indicate a significant expansion of both wind and solar capacity over the next three decades. The exact mix between wind and PV is highly sensitive to assumptions around 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, including this study. Scenario A, which results in the highest rate of new VRE capacity from this study broadly aligns with the upper end of the range from other sources. 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)	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

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

4.6.2 Supporting a High Penetration of Variable Renewable Energy

To support a growing proportion (i.e., penetration) of variable renewable energy in the energy mix it is important to consider how the variable production is balanced (so that supply and demand is matched to deliver a reliable and secure supply) and how the generation is collected and transmitted to the load via the grid.

4.6.2.1 Balancing the Variable Renewable Energy Production

Since electricity supply and demand must be exactly balanced at all times, introducing variable output generation technologies, such as solar PV and wind, requires careful balancing from dispatchable generation technologies to ensure a reliable and secure supply. As the penetration of variable renewable generation capacity increases, so must the capability of dispatchable generation to balance the increased variability.

However, 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 that these types of power plants are designed for is limited, compared to other technologies i.e., increasing the number of starts and stops, will decrease their remaining expected life. BESS and pumped hydro storage (PHS) storage schemes are well-suited to providing shorter-term (i.e., seconds up to several hours) of balancing support to the grid, while OCGT power plants are well suited to providing longer-term (i.e., minutes up to several days) of balancing support.

This study applied an iterative approach between OSeMOSYS and FlexTool to arrive at the least cost energy mix which is capable of balancing 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 and beyond.

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 Review of the IRP 2023, and this study.

Table 23: Comparison of Dispatchable Generation Capacity (GW) (excl. coal, nuclear) by 2030

Energy Source	**IRP 2019**	**Draft IRP 2023**	**Draft IRP 2024**	**Meridian[22]**	**This Study**
Gas	9	12	6	CO2040: 8	A: 9

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

				LRL: 8 BC: 8	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: IRP (DMRE), 2019; Draft IRP (DMRE), 2024a; Draft IRP (DMRE), 2024b; Meridian Economics, 2024

Scenario A from this study, which involves the most accelerated expansion of VRE and decommissioning of existing coal plants, results in the largest capacity of gas and BESS by 2030. Compared with the various IRPs and Meridian’s independent IRP analysis, the quantum of new gas capacity is relatively aligned, while the new BESS capacity is substantially larger in Scenario A. This is due to Scenario A having a relatively larger capacity of VRE which needs to be supported by 2030.

Scenarios B and C have a smaller quantum of VRE capacity by 2030 and hence require a similarly smaller quantum of gas and BESS to support this. The capacity of gas and BESS envisaged by the various IRPs and Meridian both surpass the capacities required by this study for Scenarios B and C.

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

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

Energy Source	Draft IRP 2024	Meridian[23]	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

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

Pumped Storage	-	-	A: 5 B: 5 C: 5
Total	40	CO2040: 85 LRL: 85 BC: 67	A: 81 B: 64 C: 59

Sources: Draft IRP 2024 (DMRE), 2024b; Meridian Economics, 2024

In general, the energy model developed for this study tends to construct less gas capacity than the Meridian and IRP models. Sensitivity case 9 (pessimistic RE learning rates) and Sensitivity case 13 (reduced carbon tax) from this study result in 6 GW and 4 GW 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 RE Build scenario.

In terms of trends observed from this study, it is noteworthy that Scenario A with the largest capacity of VRE and lowest CO_2 emissions, results in the lowest gas capacity and highest BESS capacity by 2050. While Scenario C with the smallest capacity of VRE and highest CO_2 emissions, results in the highest gas capacity and lowest BESS capacity by 2050. This appears logical and suggests that the lowest cost approach to achieve less CO_2 emissions is to shift from gas, towards BESS (charged by VRE). However, both technologies are still required.

4.6.2.2 Collecting and Transporting Renewable Energy Production

The identified grid requirement is in line with the TDP 2024 where there is a high requirement for transmission expansion and strengthening to collect generation from the high RE resource areas in the Greater Cape provinces. The TDP proposes the need to develop the three main 765 kV corridors collecting power from the 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 cheaper variable RE generation as discussed in Section 4.4.3. Over and above the 765 kV and 400 kV lines, the TDP 2024 also proposes the need for approximately 210 transformers totalling 133,000 MVA transformation capacity to enable the integration of distributed RE projects into the transmission grid.

Integrating variable renewable energy projects with inverter-based technology can be challenging, especially when there is a high generation quantum in an area that does not have a short circuit contribution such as in the Northern Cape. NTCSA has proposed eight synchronous condensers in the Greater Cape area to address both the inertia loss from retiring coal-fired power plants and to increase the efficacy of the grid to integrate inverter-based variable RE projects. These synchronous condensers will be vital in integrating the wind and solar PV capacities proposed in this study.

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 to procure local engineering, procurement, and construction (EPC) partners that will be capable of executing this accelerated transmission build relative to the previous decade build. To address this, NTCSA has 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 modernising 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 allows independent transmission providers to finance, design, build, and operate transmission infrastructure, with assets ultimately transferring to state ownership under the National Transmission Company of South Africa (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 coal plants out of their existing fleet of fifteen by 2030, as well as two more by 2035. As far as Eskom is concerned, as coal plants are decommissioned, additional generation capacity of 57 GW and storage capacity of 10 GW will be necessary to address the prevailing energy security challenges Eskom (2022a). As noted in Section 4.6.1.1, a significant share of this capacity has already been identified in the 2024 South African Renewable Energy Grid Survey, where Type A projects — which are 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 Air Quality Retrofits on Decommissioning Timelines

As described in Section 4.3.3, this study employed decommissioning deadlines for the Eskom fleet and allowed the model to decide on a plant-by-plant basis, whether it should continue to operate up until its decommissioning deadline or should cease operations earlier than the deadline. The decision is based on least cost optimisation as well as any additional constraints in the model, such as CO_2 emissions limits. As described in Section 4.3.8, air quality (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 decide whether to pay the cost associated with AQ compliance and allow the plant to continue operating or cease operating. Noting that the cost of AQ retrofits is approximate due to limited available information (as discussed in Section 4.3.3), the timing of AQ compliance appears to have a significant impact on the decommissioning of the coal fleet in this study.

Scenario A, which mandates AQ compliance by 2030, results in decommissioning of 23 GW of the coal fleet by 2030, with 14 GW remaining online thereafter (being Medupi, Kusile, Majuba, Kendal, Lethabo, and Matimba). The plants which remain online beyond 2030 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 thereafter (being 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 from 2040.

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

For Sensitivity Case 7 (Delayed Coal Decommissioning), the model allows coal plants to remain operational for longer periods — effectively deferring their planned decommissioning dates. Importantly, this result 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 run up until 2040 after receiving AQ retrofits in 2035. Kendal never gets decommissioned and forms 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 drive divergence in the speed and extent of coal phase-out.

In the IRP 2024 Base Case and Meridian's 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 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 only 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 reducing further to 9.9 GW by 2045 — this 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 tracking 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) from 2030, 2040, and 2050

Year	Draft IRP 2024[24]	Meridian[25]	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

Sources: Draft IRP 2024 (DMRE), 2024b; 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 IRP 2024's delayed coal schedule.

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[24] *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*

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

4.6.3.2 Carbon capture and storage

As described in Section 4.3.7, the energy model for this study included a technology option for carbon capture and storage (CCS) retrofits to existing coal power plants. Unlike the mandating of AQ compliance, CCS was only provided as an option for the model to select from beyond a certain date. The model would decide whether to deploy CCS based on lowest cost optimisation and meeting constraints such as the CO_2 emissions budget.

The model chooses to deploy CCS in both Scenario A and Scenario B. In both scenarios it is deployed only for Medupi, Kusile and Majuba, which are the three coal plants with the longest remaining life. For Scenario A it is deployed in 2035, and for Scenario B in 2040.

The immense scale of CCS retrofit required for these power plants compared to the current scale of CCS deployment worldwide is clearly a risk. If CCS deployment continues to grow at a compound annual rate of 32% as it has since 2017 (which is probably 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 lowest cost option). If the Capex of CCS is increased by 30% from the current Capex forecast, it is no longer deployed by the model and all coal plants are decommissioned by 2045. To fill the gap in demand, the model alternatively deploys an additional 14 GW of solar PV, 6 GW of wind, and 7 GW of BESS (compared to Scenario B) which increases the total generation cost (up to 2050) by approximately 9% (compared to Scenario B).

It is noted that neither the IRP or the Meridian Independent IRP models deploy CCS, and this is most likely because of differing cost assumptions and/or technologies which are made available for selection between the models.

4.6.3.3 New nuclear

New nuclear generation was made available as a technology option in all Scenarios and Sensitivity cases. None of the scenarios (A, B or C) opt 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 aimed at identifying the approximate price point where nuclear would be selected by the model. 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.

It should be noted that Sensitivity case 12 (Higher Gas Price: +30%), which increases the gas price by 30% compared to Scenario B, did not result in new nuclear capacity. The price point of gas at which new nuclear would be selected was not tested in this study.

The Draft IRP 2024 Reference Case Build Plan (up to 2050) and all scenarios and time horizons in Meridian’s Independent IRP analysis 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 shows a net-zero CO_2 goal will be achieved in 2050, and an overall GHG emissions budget over the period 2021 to 2050 of 7.8 to 8.5 Gt CO_2e (The Presidency, 2022). Modelling conducted by UCT’s ESRG for the World Bank Group’s Country Climate and Development Report (Marquard et al., 2021; World Bank, 2022b) to apportion greenhouse gas emissions per sector, provides a budget of approximately 2.5 Gt CO_2e for the power sector between 2023 and 2050, based on an economy-wide budget of 9 Gt CO_2e over the period 2021 to 2050.

In specific relation to decarbonisation and net-zero, Eskom expresses in the JET-Factsheet#1 that net-zero implies having some residual emissions, which will be reduced by carbon-absorbing technologies. Eskom adopts the view that these technologies will advance in the future, however Eskom also recognises the JET is part of the long-term strategy to transition the business 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 industrialisation and reduction of CO_2 emissions. The result of Scenario A represents the lowest 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 industrialisation and CO_2 emissions reduction and represent the lowest cost energy mixes to achieve 3.1 Gt 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 variable renewable energy. According to Meridian Economics (2023), such an outcome aligns with credible net-zero pathways, where the carbon budget is strategically allocated to emissions from flexible peaking plants. These plants can later transition to green hydrogen or ammonia as fuel sources, enabling full decarbonisation. Importantly, it is also noted that the cost impact of such residual emissions should be minimal, as peaking fuel comprises only a small fraction of total system costs at that point in the energy transition (Meridian Economics, 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), 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 greenhouse gas 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 and the demand gap made up with additional VRE and BESS in order to 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. In reality, 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.

On the other hand, countries that do not adhere to their NDCs under the Paris Agreement will affect other countries’ decision-making around their investment into a country which 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 remaining economically competitive in the global market.

The transition to affordable, reliable, sustainable, and modern energy services is reliant on the learning rates of new generation technologies to be sufficiently high enough 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 RE 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

From our analysis the investment requirements for the various scenarios in real 2024 prices are summarised in the table below.

Table 26: Investment Requirements (2025 to 2050) (R billions, Discounted at 8% to 2024)

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 the table below. While the values were obtained across several studies which investigate the energy infrastructure needs of South Africa, they speak to 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 billion)	Period (Range)	Average annual investment (R billion)
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
NBI	2 840	2020 – 2050	95
BFT	3 225	2022 – 2050	115
Eskom	1 119	2022 – 2035	86
World Bank[26]	1 803	2015 – 2030	113
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); NBI (2022); Blended Finance Taskforce (2022); Eskom (2022) and Rozenberg and Fay (2019) for the World Bank Group, WEF (2024).

The rationale behind these quanta, given the various criteria and assumptions that were considered in each report, are:

- **Meridian**: Meridian Economics Review of the IRP 2023, as discussed earlier in this report, includes similar modelling as was conducted for this study for a number of different scenarios. The three scenarios compared earlier in this report are included below for comparison (i.e., Base Case RE Build, Likely RE Learning, and Coal off by 2040) – these scenarios are based on similar cost and performance parameters as this study. An additional scenario “IRP 2023 Cost Assumptions” is also included, which is a least cost optimisation 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 i.e., the figures should be close, but not exact. Finally, while the Meridian report considers grid constraints, it did not include grid costs. Therefore, the total costs presented for these scenarios are total generation costs (Meridian Economics, 2024).
- **JET-IP:** The JET-IP establishes an investment target of R 647.7 (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, new PV, new wind, and new batteries. The average annual investment to address the national electricity infrastructure requirement is therefore estimated to be R 130 (USD 8.6) billion.

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[26] *Please note that this is a range for sub-Saharan Africa.*

- **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, Agriculture, Forestry and Other Land Use (AFOLU) and building and construction sectors. When isolating the power sector investment focus for the NBI study, which includes generation and grid expansion costs, this value amounts to R 2 850 (USD 189.3) billion over 30 years (2020 – 2050) and averages to R 95 (USD 6.3) billion annually.
- **BFT:** The Blended Finance Taskforce (BFT) expresses the following breakdown of their energy sector finance investment estimate: RE build out (R 1 875 / USD 125 billion), flexibility in relation to electricity storage and gas (R 750 /USD 50 billion), transmission and distribution (R 600 / USD 40 billion), green industrialisation (amount not stated), early retirement of coal plants (R 360 / USD 24 billion), climate justice outcomes (R 150 / USD 10 billion). Isolating purely infrastructure related estimates, incorporating RE (R 1 875 / USD 125 billion), grid flexibility (R 750 /USD 50 billion) and new transmission and distribution (R 600 / USD 40 billion) equates to R 3 225 (USD 215) billion between 2022 - 2050. This results in an average of R 115 (USD 7.7) billion investment estimate annually for 2022 - 2050.
- **Eskom:** In the JET Change Management Fact Sheet #5 Eskom indicates that their total funding required by 2035 amounts to R 1 200 (USD 80) billion (Eskom, 2022). Isolating energy infrastructure costs, by 2035 Eskom estimates that R 947 (USD 63.1) billion would be necessary for additional generation and storage, R 120 (USD 8) billion for transmission infrastructure, and R 52 (USD 3.5) billion for the distribution network to be strengthened. This translates to R 86 billion per annum over the period 2022 - 2035.
- **World Bank:** The World Bank proposes a multi-tiered approach towards provisioning electricity in sub-Saharan Africa, across basic, middle range, and high-quality access scenarios. The mean of the forecast investment ranges results in an average annual investment requirement of USD 7.5 (R 113) billion from 2015 to 2030, which equates to USD 120.2 (R 1 803) billion over 16 years (Rozenberg and Fay, 2019). This value from World Bank (2019) is based on % GDP values applicable to low middle income countries (LMIC) whereby the lowest energy access (basic) ranges between 2.1 – 2.2% of a country’s GDP and the highest access tier (high quality) sits at 2.5 – 2.8 of a nation’s GDP. An average of 2.5% of GDP was applied to South Africa’s GDP for 2021/2022 of R 4 600 (USD 306.7) billion. The World Bank report employs the GDP % tiers as a mechanism to distinguish between energy infrastructure targets.
- **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 around R 245 (USD 16.3) billion by 2030, however generation capacity would be highly constrained by insufficient transmission on-take availability. The partnership therefore articulated that the additional infrastructure investment required for transmission capacity is estimated at R

390 (USD 26) billion. Collectively, the physical infrastructure electricity investment put forward by the working group to transform the South African energy sector by 2030 would amount to R 635 (USD 42.33) billion (WEF, 2024a). This sum translates to R 106 (USD 7.05) billion annually up to 2030.

The average investment requirements of the studies considered here range between R 86 billion to R 157 billion annually (considering different timeframes). The range from this study is R 137 to R 160 billion annually. The ranges overlap with the upper end of the range from this study extending slightly above the range from the comparison sources. The upper end of the comparison sources were the Meridian scenarios 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, the Meridian Economics study is the most comparable to this analysis in both scope and assumptions. Like this study, Meridian explicitly evaluates the impacts of accelerated coal decommissioning, declining renewable energy technology costs, and constraints on wind deployment. Meridian’s “Likely RE Learning” and “Coal off by 2040” scenarios in particular align closely with Scenarios A and B of this study. Meridian’s pathways also internalise carbon pricing and emissions limits, producing results in terms of generation mix, emissions reduction, and system cost impacts.

The following Sections provide context to the discussion on the funding levels under each scenario, given South Africa’s unique socio-economic circumstances and general uncertainty when dealing with a 25-year timeline.

4.6.5.2 Variables

The following indicates some of the key variables which can impact the investment requirements for electricity infrastructure from countries who have adapted renewables into their energy mix:

- **Upfront costs**: The variability around high initial investment which speaks to frontloading 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 realised, hence scaling up (green infrastructure) to phase down (fossil fuel infrastructure) (World Bank, 2023). Scenarios A, B and C from this study considered a range of technology learning rates, and the results in this respect have been discussed already.
- **Government incentives:** Government incentives represent a major factor in determining capital expenditure 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 cost of capital) and the results of these have been discussed already.

- **Running costs:** Aside from capital expenditure-related costs, operating and maintenance costs may define a sizeable portion of the subsequent energy pricing. The energy-utility death spiral is a phenomenon which relates how ageing and inadequate infrastructure relay costs back to energy consumers, as is the case with conventional coal fired-power stations (Athawale & Felder, 2022). Compared to fossil fuel power plants, renewable energy facilities have lower operating and maintenance costs, however technical ability may still drive operational expenditure costs in skill-scarce regions. Fundamentally, solar and wind farms in relation to fossil energy plants, require minimal ongoing expenses 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 & Jaipal, 2022). However, in South Africa, transmission and grid integration are expected to present a major source of pricing variability due to the lack of 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 to legacy and future systems that may arise from climate change. This may directly affect power generation which relies on wind and sun availability (Yalew et al., 2020). Scenarios A, B and C, and two sensitivity cases from this study, considered a range of different fuel prices, and the results of this have been discussed already.
- **An enabling policy environment:** Supportive policies, such as feed-in tariffs or renewable portfolio standards, can impact the distribution of costs by providing financial incentives or requiring a certain percentage of energy to come from renewables (Kumar & Jaipal, 2022; Qadir et al, 2021). South Africa’s energy and climate policy has been evolving over the past decades and key instruments are discussed in subsequent sections of this report.

4.6.5.3 Barriers and Trade-offs

The financial implications of the energy infrastructure scenarios are crucial for ensuring 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, especially for renewable energy projects, remains a critical challenge (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 & Andtshamano, 2024).

Low emission development and economic decarbonisation 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 decarbonisation objectives of South Africa’s NDCs under the Paris Agreement (UNFCCC, 2022).

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 NT will not significantly contribute to the new generation, transmission, and distribution infrastructure required from 2025 to 2050. Therefore, limited financial and technical resources may need to be prioritised, potentially leading to trade-offs between different goals. For instance, 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 prioritising electricity expenditure over road infrastructure maintenance.

Effective policies and international investment and support are crucial to balance these trade-offs, 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

National Treasury released the 2023 Budget Review which focused on Eskom debt relief. The review states that a debt-relief arrangement is being set up to cover R 254 (USD 16.9) billion of Eskom debt. The debt relief covers approximately R 168 (USD 11.2) billion in capital and R 86 (USD 5.7) billion in interest, over the next three years, with strict conditions. Of note is that a condition for the bail out is that Eskom’s capital expenditure is restricted to transmission and distribution development (NT, 2023).

Initiatives to attract private sector investment through Independent Transmission Projects (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, 2025; Eskom-NTCSA, 2024).

The JET-IP emphasises upgrading transmission and distribution networks to accommodate the renewable energy generated by the private sector, ensuring energy security and decarbonisation (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, 2025). TDP 2024 expresses the installation of 14 494 km of transmission lines and 210 transformers, thereby adding 133 GVA of capacity, which is envisaged to significantly boost the grid's ability to handle increased load and integrate these new generation sources. The preceding TDP 2022 expressed that 53 GW of new generation capacity will need to be integrated, from all technologies, by 2034. This was increased to 56 GW by 2034 in TDP 2024 (Eskom-NTCSA, 2025).

The installation of synchronous condensers at seven sites and additional transformers at existing substation sites will ensure 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, 2025).

With a total estimated capital of R 112.5 billion from FY25 to FY29 (annual average of R 23 billion), including R 85.6 billion for capacity expansion, TDP 2024 seeks to address current network constraints and supports 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 R 120 billion (annual average of R 10 billion) (Eskom, 2022). In addition, Eskom’s JET fact sheet five estimated that upgrading and bolstering of the distribution network would amount to around R 52 billion by 2035 (annual average of R 4 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 R 231 billion (Scenario C, annual average of R 9 billion) to R 383 billion (Scenario A, annual average of R 15 billion).

4.7 Conclusion

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 industrialisation and reduction of CO_2 emissions. Scenarios B and C are based on progressively less local and global focus on green industrialisation and CO_2 emissions reduction. Model input assumptions vary across the Scenarios, based on the external context for that scenario.

In all scenarios, the largest component of new generation capacity consists of variable renewable energy technologies i.e., solar PV and wind, supported primarily by new BESS and gas generation capacity. The scale and rate of solar PV, wind, BESS and gas capacity expansion varies between the scenarios, driven by various changes in input assumptions (such as technology learning rates, fuel prices, carbon tax, etc.) and model constraints (such as CO_2 emissions budget, and 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, assuming that 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 2024, PCC 2023a) and the total quantum of new solar PV and wind capacity required by 2030 is less than the current pipeline of projects captured in Eskom's Renewable Energy Grid Survey 2024 (Eskom, 2024c).

Even with the optimistic technology learning rates, Scenario A requires the largest up-front capital investment for new generation capacity and grid capacity (to collect and transport the large quantity of renewables) amongst the three scenarios (when comparing based on costs discounted to 2024). However, due to the reduced requirement for fuel (since renewable energy contributes the largest portion of the energy mix and does not require fuel), combined with lower fuel prices (an input assumption relevant to this scenario), the total investment requirement (being the combination of all Capex and Opex costs for generation and grid infrastructure) is the lowest amongst the three scenarios. Furthermore, Scenario A achieves the lowest CO_2 emissions.

Scenario A, however, is not without its challenges and trade-offs. The large Capex investment requirement versus the available funding (as discussed further in 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, fuel prices, etc.) must all be considered. The influence of external / global conditions which also impact key assumptions such as fuel prices, technology learning rates, technology readiness (in the case of CCS), and global commitments and policies relating to CO_2 emissions reduction must also be considered.

Scenarios B and C, on the other hand, 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, Scenario C represents the least cost approach with no CO_2 emissions budget (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 to a lesser extent than Scenario A, with an overall lower capacity of new 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 UCT’s ESRG, the World Bank’s South African Country Climate and Development Report, and the JET IP (Marquard et al., 2021; World Bank, 2022b; The Presidency, 2022).

In terms of total investment requirement, due primarily to the less optimistic technology learning rates and higher fuel prices in Scenarios B and C, the total system investment is 2% and 16% higher for Scenarios B and C respectively, compared to Scenario A. 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 Transmission Development Plan (Eskom-NTCSA, 2024) 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 envisages a higher capacity than what is reflected in the TDP and Strategic Transmission Corridors. This may be due to the TDP and Strategic Transmission Corridors focussing on a medium-term time horizon (up to 2034), as opposed to this study which focusses on a longer-term time horizon (up to 2050).

4.8 Recommendations

Scenario A is consistent with a local and global green transition, is 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[27]. Subject to assessment of the socio-economic impact of Scenario A (to be included in a supplementary report) and subject to the realisation of the local and global pathway assumptions (in particular, renewable energy technology learning rates) relevant to Scenario A, it is recommended to pursue the technology transition, energy mix and associated investment requirements of Scenario A, as summarised in Table 28. Since achievement of Scenario A is conditional on the realisation of the local and

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

global pathway assumptions relevant to this Scenario, it is recommended that Government should, where possible, pursue policy decisions which enable this pathway and its associated assumptions.

Table 28: Quantified recommendations for Scenario A

Metric	Units	2030	2040	2050
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[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.	122	15	8
Annual average Capex investment[29]	R bn p.a.	227	176	176

Scenario B is premised on a local and global environment which is less focussed on a green transition and as a result 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. Under 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. 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. The major difference between Table 28 and Table 29 is the coal capacity.

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

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

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 (Engelbrecht, 2021).

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[30]	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[31]	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 / 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 focussed on a green transition, 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

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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 at 8% to 2024 prices. Excludes generation Opex.*

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 Scenario A or B in response to wider climate impacts resulting in Southern Africa warming at twice the global rate (Engelbrecht, 2021).

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[32]	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[33]	R bn p.a.	142	191	191

Noting that South Africa has limited control of the external, global pathway assumptions, and that local pathway assumptions are somewhat linked to the global assumptions, it is difficult to concretely recommend the most optimal capacity, energy mix and CO_2 emissions trajectory. With this in mind, the following broad recommendations apply across the range of pathways and related scenarios considered in this study:

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

[33] *Includes generation and transmission (including distribution collector networks) Capex, discounted at 8% to 2024 prices. Excludes generation Opex.*

- **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 ESRG, all recommend focusing on a significant expansion of VRE as part of the least-cost energy solution (Tyler et al., 2023; Roff et al., 2023; Meridian Economics, 2024; CSIR, 2020; Renaud et al., 2020).
- **Incorporate gas and battery storage to support VRE technologies:** This study, again supported by various others (as listed in the previous point), 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 are effective for stabilisation requirements measured in seconds and hours, while gas is more suitable for stabilisation measured in hours to days (The Presidency, 2023; NREL, 2019). It is important to note that gas is not adopted as an alternative "baseload" power source to coal, due to its higher costs, price volatility given that it is traded in US dollars, as well as its higher carbon footprint relative to VRE (IEA, 2023).
- **No new coal and nuclear plants:** Results from the least cost modelling in this study, supported by the findings from other similar studies (Tyler et al., 2023; Roff et al., 2023; Meridian Economics, 2024; CSIR, 2020; Renaud et al., 2020), 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. It is not just a question of reduced costs of nuclear, but also the real possibility that the costs of VRE start to rise in the 2030s as the natural resource constraints affect supply of materials for VRE construction if the whole world commits to an accelerated energy transition (WEF, 2024b). Either way, in the unlikely event that nuclear does become affordable *in the near future*, it could only come on stream at the earliest in mid-2030s. More likely, for a small 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) which had a strict mandate for AQ compliance (2030 and 2035, respectively) opted to decommission the coal plants which had a shorter remaining life, leaving only Medupi, Kusile, Majuba and Kendal (Scenario A only) in operation. This suggests that from a least cost perspective it is more economical to decommission plants with shorter remaining life, than to deploy AQ retrofits and keep them operational. A thorough cost-benefit analysis, based on plant-

specific cost estimates, should be conducted prior to investing in AQ retrofits for plants with shorter remaining life

- **Investigate and monitor feasibility of CCS technology:** CCS is deployed in both Scenarios A and B for the plants with longer remaining life, i.e., Medupi, Kusile, Majuba and Kendal (Scenario A only). While CCS technology deployment is growing internationally, its current scale and maturity is far from what would be required to implement on these power plants. The future feasibility and cost effectiveness of utility scale CCS will depend on, amongst other things, its rate of adoption globally. If available and commercially viable at scale, CCS is deployed in 2035 and 2040 in Scenarios A and B respectively, which gives some time for this technology to mature and potentially reach the cost projections and required scale / maturity 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, it is imperative that the existing coal fleet meets its availability targets, and that transmission and distribution infrastructure can reliably and efficiently transport electricity to consumers.
- **Co-locate RE generation infrastructure with demand:** Co-locating RE generation infrastructure with demand centers, such as industrial parks, data centers, or urban areas, can significantly reduce transmission losses and improve energy efficiency. Co-location can facilitate the integration of RE sources with local energy needs, 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 supplants the now outdated baseload approach which was about 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. There is a large focus, globally, 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 most notably small modular reactors (SMR), offshore wind, long duration energy storage, and grid digitalisation.
- **Consider policy and regulatory changes which support green industrialisation and reduction of greenhouse gas emissions:** As observed from Scenario A in this study, with

a favorable set of local and global conditions (similar to the assumptions made for Scenario A, as detailed in Section 3.3) a transition to a secure, reliable, modern and affordable electricity system which meets South Africa’s NDC targets can be achieved. Key policy aspects to consider, informed by the policy assumptions which impacted the energy modelling, include sufficient carbon tax levels, mandatory requirement for AQ compliance, enabling low VRE and BESS/gas technology costs, and enabling low fuel costs. Further discussion on policy and regulatory aspects is provided in Section 7.

5 Energy Infrastructure Funding Gap Market Sounding

5.1 Introduction

One of the key research questions of this study is to understand the potential energy infrastructure funding gap (“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 detailed below:

1. **Required capital:** meaning the projected required levels of capital expenditure (excluding operating costs, capitalised interest and funding costs) to support the required energy infrastructure rollout up to 2050.
2. **Available capital:** meaning 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.

As such, a soft or informal[34] market sounding 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 real terms, excluding operating costs, capitalised interest and funding costs) over the forecast period up to 2050 (see Figure 44 below). At the time of the market sounding interviews, the technical modelling was still on-going, and as a result, the estimate of approximately R 100 billion (in real terms) per annum from 2024 to 2050 was derived from the Draft IRP 2023, as well as reputable public sources of information to frame OEG’s initial estimates and assumptions for the required capital (capital expenditure quantum, technology mix and phasing).

The assumptions applied to frame the required capital are approximate and were based on the expected electricity generation, transmission, and distribution infrastructure requirements for South Africa over the forecast period to 2050. This figure is to be seen as notional, and was used as a basis to engage with participants during the market sounding. Further detail in this regard is provided in the methodology section 5.2, as well as the assumptions and limitations section 5.3.

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[34] *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 submit answers before the meeting.*

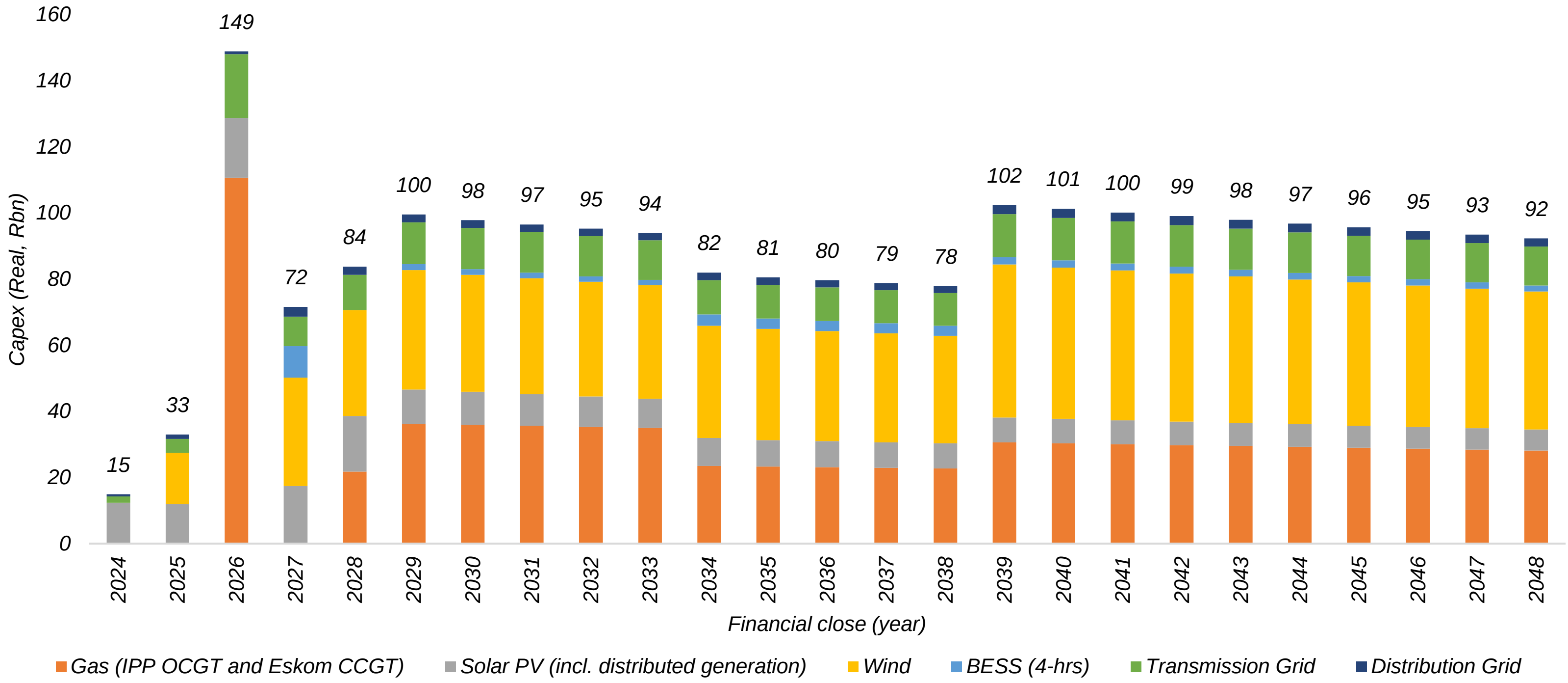

Figure 44: Estimated Forecast Capital Expenditure for Energy Infrastructure in South Africa Used for the Market Sounding (Real terms, R' billions)[35]

Sources: Department of Mineral Resources and Energy, 2023; OEG assumptions

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

5.2 Methodology

To understand how to quantify and address the potential funding gap, a market sounding exercise was undertaken with a limited number of key prospective providers of capital - referred to as market sounding participants - who are active in the energy market in South Africa. These market sounding participants were selected to represent a balanced market perspective, and comprise the following categories listed in Table 31 below.

Table 31: Prospective Funders / 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 focussed funds)	• Government • Treasury • Infrastructure Fund	• Local commercial banks

The market sounding was conducted by way of an informal interview with market sounding participants. A market sounding briefing document (market sounding interview guide) was shared with participants in advance of the interview, which contained an overview of the team’s existing mandate including the rationale for the market sounding, as well as the assumptions and a market sounding questionnaire positioned to understand the prospective levels of available capital, and current challenges and key enablers to direct the deployment of additional funding into the energy sector.

5.2.1 Market Sounding Interview Guide

With reference to the agreed 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 incentivise 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 the allocation towards energy infrastructure investments within 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 allocation of funds within the South African energy infrastructure market.
- Appetite of market sounding participants to take 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, the responses from the market sounding participants were evaluated comprehensively, for each key theme identified, and captured on the scale. It is important to note that while the scoring system provided a quantitative measure of the response, qualitative aspects such as the depth and clarity of the responses were also appropriately considered.

5.2.3 Report Development

From the results of the market sounding exercise captured in the output matrix, a report was developed to address the key research questions relating to the funding gap. Furthermore, this Section of the report will be used as an input to assist in estimating the finance options for the funding gap as well as to support the regulatory and policy analysis Section of this report.

5.3 Assumptions and Limitations

As mentioned in the introduction and background Section, at the time when the market soundings were conducted, the technical modelling workstream was still being finalised. As a result, OEG utilised the

Draft IRP 2023, as well as other reputable sources of information and their own assumptions as a basis for annual capital expenditure per technology, learning rates, and the phasing thereof. As such, the required capital was indicative, and the market sounding process did not look to test or verify such assumptions 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.
- For the purposes of determining the level of the funding gap (if any), an assumption of c. R 100 billion of total funding required per annum until 2050 has been assumed (in real terms and excluding operating costs, capitalised interest and funding costs). This was based on OEG's initial estimated total required capital of c. R 2.2 trillion (in real terms, excluding operating costs, capitalised interest and funding costs) over the forecast period up to 2050[36].
- The rationale for utilising the R 100 billion annual number in real terms and excluding operating costs, capitalised interest and funding costs is due to the following:
- To determine the operating costs, capitalised interest and funding cost components which typically make up part of the project size / costs, a detailed financial modelling exercise would need to be undertaken on a project-by-project basis. In the absence of such project and funding information, this task would not be possible nor 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 contextualise the capital expenditure requirements without having to make significant assumptions on forecast funding rates, CPI, etc.
    - For ease of the discussion with market sounding participants to ensure that the focus remains on the questions aimed at understanding the funding gap (listed in Section 5.2.1 above), and to avoid detailed and unnecessary discussions of underlying assumptions of the capex.

The following limitations apply to the market sounding:

- Due to the inherent confidentiality and the commercial sensitivity of the innovative funding approaches, there is a potential limitation that the market sounding participants have not shared innovative funding approaches which they have considered in the South African energy infrastructure market. This is due to the threat which this may pose on the market sounding

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

participant/s' commercial objectives. Furthermore, the market sounding participants may be sceptical to share certain information due to the risk of disclosing inside information.

- Given the varying commercial objectives that different types of market sounding participants have (i.e., debt funders are more conservative from a risk exposure perspective than equity funders), there is an inherent limitation on comparability for the outputs and key themes which have been identified as market sounding participants have not consistently identified the same outputs and key themes throughout the market sounding exercise. As such, some market sounding participants have not been included in each output and key theme discussed in the Section which follows.

5.4 Findings

5.4.1 Quantum of Funding Available to Solve for the Funding Gap

As indicated in Figure 45 below, the majority 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 (detailed in the Findings discussion section 5.5.1). In addition, local commercial banks are confident that round seven of the REIPPP will be fully funded.

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

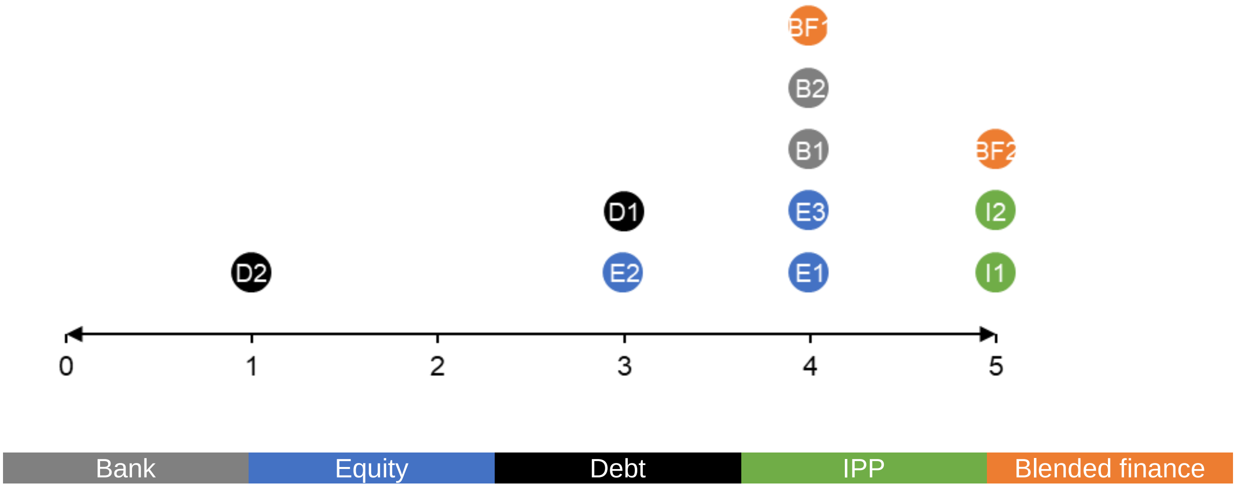

Figure 45: Funding Quantum Available Over the Short-to-Medium Term

5.4.2 Pricing as a Limitation to Financing of Renewable Energy Infrastructure

As indicated in Figure 46 below, the market sounding participants indicated that pricing is a significant barrier / limitation to the financing of renewable energy infrastructure in South Africa. Market sounding participants believe that this is primarily due to the highly competitive nature of the current energy infrastructure market, particularly for generation energy infrastructure, where pricing levels on debt funding instruments and the returns for equity providers are becoming less as they no longer compensate funders / investors adequately for the associated risks taken for these generation energy 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)

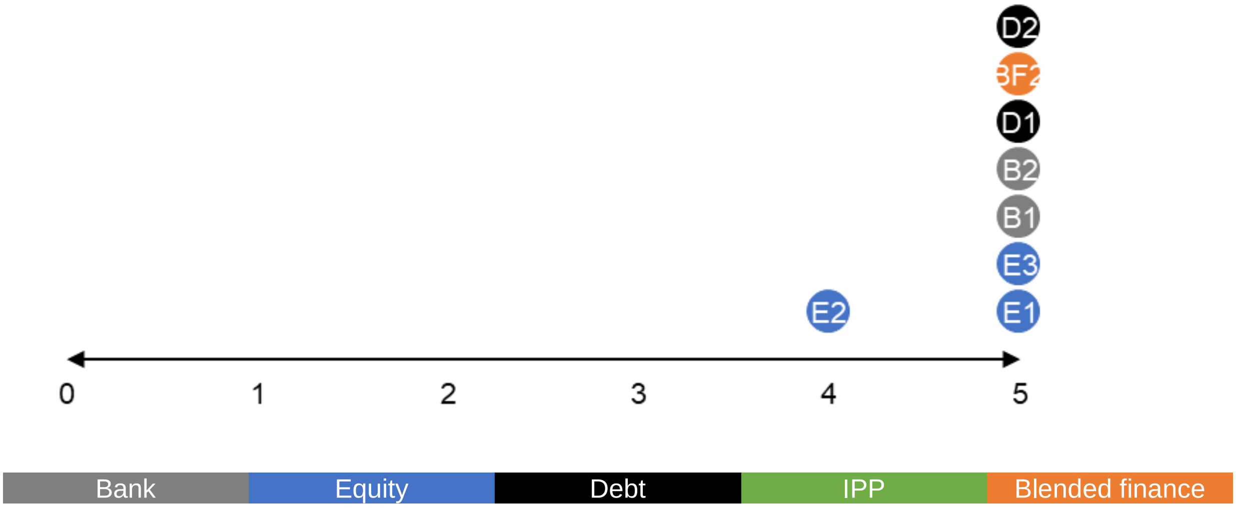

Figure 46: Pricing as a Limitation to Financing Renewable Energy Infrastructure

5.4.3 Policy Uncertainty as a Limitation to Allocating Additional Funding to Renewable Energy Infrastructure

As indicated in Figure 47 below, 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 unpredictability of policies and frameworks related to transmission and distribution infrastructure, which introduces additional complexities into the investment process. Further detail in this regard is provided under the Findings discussion section of this report (5.5.3).

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

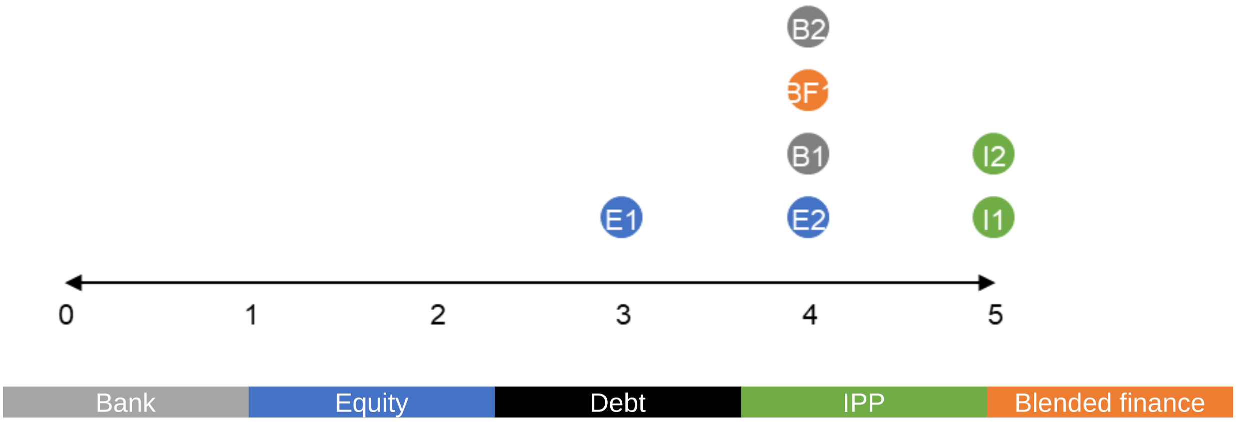

Figure 47: Policy Uncertainty as a Limitation

5.4.4 Role of Blended Finance as an Enabler of Financing Energy Infrastructure in South Africa

Blended finance refers to the strategic use of development finance to mobilise private capital flows to emerging markets. The role of blended finance has been identified as a potential mechanism to attract debt funding for investment within transmission energy infrastructure by the market sounding participants. From a generation energy infrastructure perspective however, the market sounding participants indicated limited scope given that the market is already well-established (see Figure 48 below).

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

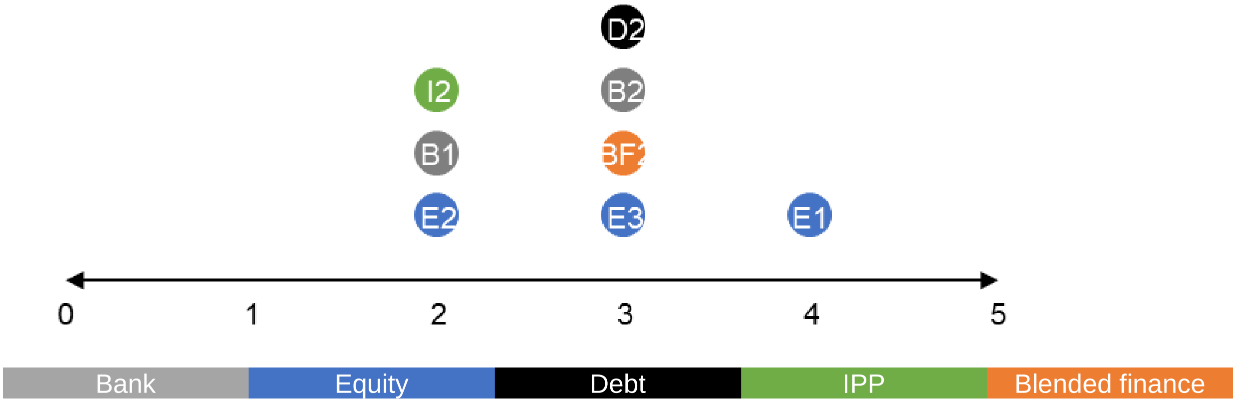

Figure 48: Role of Blended Finance as an Enabler for Financing Energy Infrastructure

5.4.4.1 Role of Credit Enhancements for Financing Energy Infrastructure in South Africa

As illustrated in Figure 49, 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. Whilst the commercial banks have indicated that credit enhancements play a moderate role in attracting debt funding, pension funds and IPPs have indicated that the role of credit enhancements are important to attracting debt funding for investment in energy infrastructure within the South African market. Further details in this regard are provided in the Findings discussion section of this report (5.5.5).

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

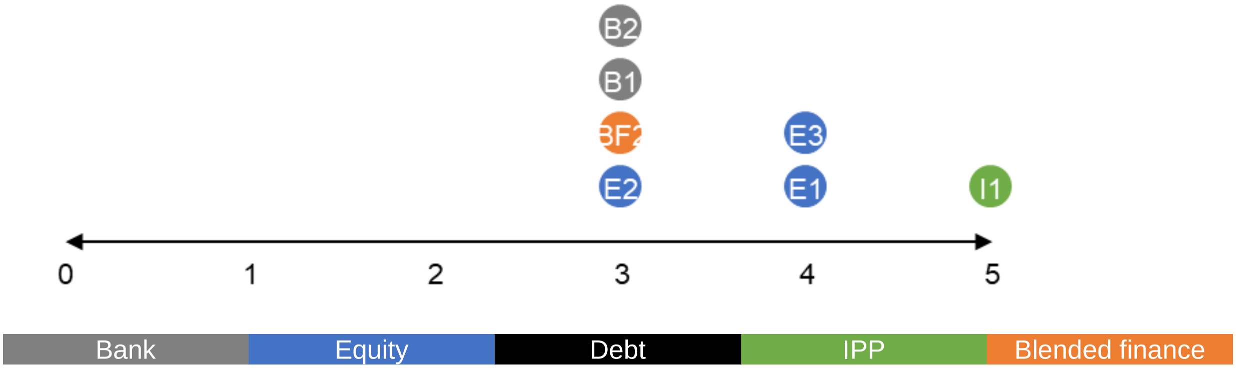

Figure 49: Role of Credit Enhancements as an Enabler for Funding Renewable Energy Infrastructure

5.4.4.2 Level of Market Risk in the Current Renewable Energy Infrastructure Environment in South Africa

As indicated in Figure 50 below, the market sounding participants largely indicated that they have little-to-no appetite to take on this market risk as the wholesale market is currently not mature enough in South Africa. However, the market sounding participants have indicated that there will be an increase of 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.

Results from the market sounding indicate that equity investors have a larger appetite to take market risk due to their view on future energy prices as well as their appetite for risk when compared to debt funders. One equity market sounding participant has indicated a stronger appetite to take on market risk in the current environment due to their views on the forecast power curve and therefore do not require long term take-or-pay arrangements.

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

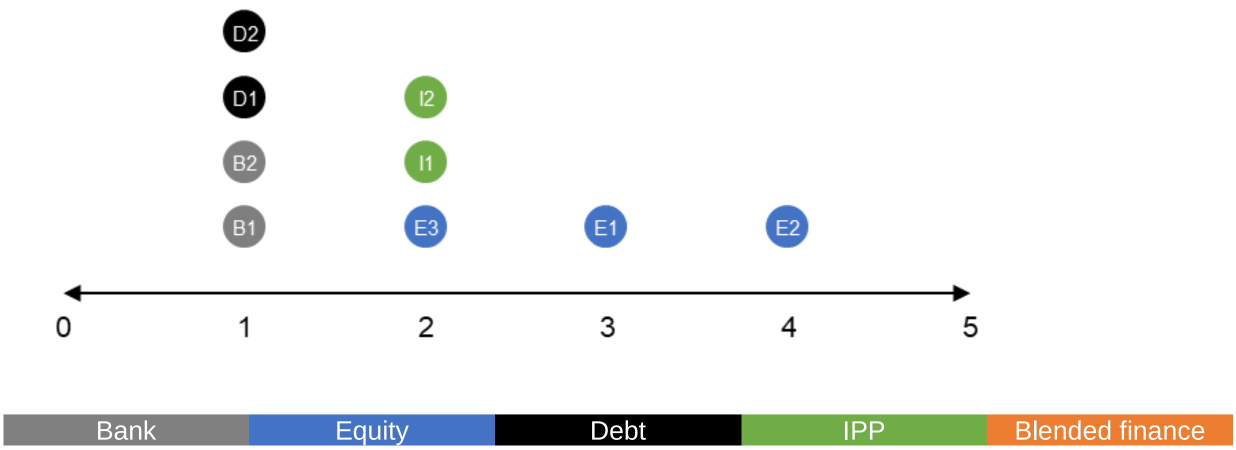

Figure 50: Level of Appetite for Market Risk Which Market Sounding Participants are Willing to Take in the South African Renewable Energy Infrastructure Environment

5.4.5 Additional Themes Identified During the Market Sounding

Based on the feedback from the market sounding participants, responses have been separated into three sub-categories being 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 of the Findings discussion of this report.

5.4.5.1 Limitations or Obstacles in Relation to Raising / Allocating Additional Funds Towards Energy Infrastructure in South Africa as Indicated by Market Sounding Participants:

- Programme inconsistency and the resultant lack of bankable project pipeline**.**
- Eskom’s inability to process the substantial number of applications for Eskom’s Budget Quote (BQ) process.
- Income Tax Act 58 of 1962, as amended (ITA), Section 23M limitation on the deductibility of interest on debt.
- Lack of clarity for transmission energy 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 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.
- 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 swops on South African Rand-based lending.
    - Longer term funding such as 30-year loan tenors for transmission energy infrastructure projects; and
    - Alternative funding and operating models can unlock funding for transmission infrastructure.

5.4.5.3 Factors Which Influence the Level of Market Risk That Funders Are Willing to Take Within the Energy Infrastructure in the South African Market, as Indicated by Market Sounding Participants:

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

5.5 Findings Discussion

5.5.1 Total Quantum of Funding Available to Solve for the Funding Gap

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 funding gap over the long-term, which is underpinned by several factors included in the limitations or obstacles listed in section 5.5.7 (Additional themes identified during the market sounding) below.

In addition to the above, it's worth noting the following responses from market sounding participants with regards to the total funding quantum available to solve for the funding gap:

- **Secondary market role**: the secondary market's ability and appetite to invest in commercial banks' debt syndication processes is a key factor to consider when determining the funding gap, because without appetite from these funders to invest in such debt syndications, commercial banks will become hesitant to continue funding additional energy infrastructure investments due to exposure limitations.

- **REIPPP round seven:** with reference to the funding gap over the long-term, local commercial banks believe that that round seven of the REIPPP will be fully funded (i.e., generation energy infrastructure will be fully funded).

5.5.2 Pricing as a Limitation to Financing Renewable Energy Infrastructure in the South African Market

The market sounding participants indicated that pricing on debt instruments remains a significant barrier when determining the funding available for investment in energy infrastructure within 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 associated risks.

For this to change, pricing across the debt and equity funding instruments must be rebalanced to become more attractive to investors, and ultimately stimulate the required funding for generation energy, distribution energy, and transmission energy infrastructure. The market sounding participants have indicated that pricing on debt funding instruments is a key contributor which will detract funders from allocating debt to energy infrastructure investment within the South African market, as pricing is no longer reflective of the risks associated with renewable energy projects.

Currently, net interest margin returns are below 200 basis points, which is deemed low by the market sounding participants and this level of pricing fails to account for the inherent risks associated with energy infrastructure investments within the South African market. 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 within South Africa.

The secondary market, specifically pension funds, which have access to a significantly large quantum of funding, will continue to balance risk and liquidity with returns on their investment portfolios in pursuit of optimal portfolio management. As such, a rational investor would prefer to invest in a listed South African 20-year Government Bond, which had a yield of c. 12.50% during June 2024 compared to syndicated debt products for financing energy infrastructure which offers a yield of c. 10.35%, being the three-month Johannesburg Interbank Average Rate (JIBAR) + 200 basis points. Debt syndication participants are not appropriately compensated for the level of risk and liquidity, which is assumed, as the debt syndication instrument is not listed on an exchange and therefore does not appropriately compensate investors for the lack of liquidity as well as the credit quality of the borrower being weaker than 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 addressed through rebalancing pricing to compensate for the associated risk.

5.5.3 Policy Uncertainty as a Limitation to Allocating Funding to Renewable Energy Infrastructure in the South African Market

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 within which the energy infrastructure developers can 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 energy 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. The aforementioned factors of policy uncertainty impact the perceived level of risk associated with energy infrastructure projects, making them less attractive to potential debt funders.

5.5.4 Role of Blended Finance as an Enabler of Financing Energy Infrastructure in the South African Market

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

The nature of transmission energy 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 transmission energy infrastructure, thereby making transmission energy infrastructure more attractive to potential debt funders such as commercial banks and pension funds, increasing the allocation of debt funding to energy infrastructure within the South African market. Blended finance can 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. The role of blended finance in gas-to-power infrastructure can be strategically positioned to provide comfort to developers and commercial lenders.

5.5.5 Role of Credit Enhancements as an Enabler for Financing Renewable Energy Infrastructure in the South African Market

The market sounding participants have indicated that credit enhancements do play a significant role to 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, whilst pension funds and IPPs have indicated that the role of credit enhancements are important to attracting funding for investment in energy infrastructure within the South African market.

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 back stops could play a significant role to ensure that an energy developer can survive unforeseen market instability and volatility during the construction period of renewable energy projects.

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

In addition, credit enhancements can play a key role in the gas-to-power midstream market to mobilise capital allocation from the private sector. First loss backstops can be used as a form of credit enhancement, whereby a Development Finance Institution (DFI) absorbs the first tranche of any losses at a predefined level.

5.5.6 Level of Market Risk in the Current Environment Which Market Sounding Participants are Willing to Take in the South African Renewable Energy Infrastructure Market

Most market sounding participants indicated that they have little-to-no 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 aggregate 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 aggregator offering terms as short as 1 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 due to no off-take agreement being in place throughout the tenor of the useful life of the energy generation assets.

Furthermore, it has been noted that shorter-term PPAs for wind renewable energy technology will be more attractive when compared to solar PV renewable energy technology, as the latter will be difficult to reprice at an attractive level from an investor's perspective given the rapid development in technological advancement and increased adoption of roof-top solar photovoltaic systems, which ultimately drives the cost of producing energy from these technologies downwards.

The commercial banks have indicated that there will be additional debt funding allocated to energy aggregators as the market matures. The market will be deemed as more mature once the Day-ahead and Week-ahead energy market in South Africa obtains additional liquidity, which will require additional market participation and regulatory reform.

The Day-ahead market operates in a manner whereby energy generators, such as Eskom and IPPs, will inform the market operator on the quantum of electricity which they expect to generate on the following day, and the level of tariff at which they are willing to sell said generated electricity. On the other side, energy consumers, such as municipalities or large industrial consumers, will inform the market operator on the quantum of electricity they require for the following day and the level of tariff which they are willing to pay for said electricity. The market operator then matches the energy sellers and buyers, resultantly, determining the next day's level of tariff for electricity.

Currently, the Week-ahead market is not formal in South Africa, however, players in the market obtain insight from forecasts such as changes in weather, availability of energy and other factors that could impact the level of tariffs for electricity.

5.5.7 Additional Themes Identified During the Market Sounding as Indicated by Participants

1) Limitations or obstacles in relation to raising or allocating additional funds towards energy infrastructure as per the market sounding participants:

- **Programme inconsistency and the resultant lack of bankable projects:** developers and commercial lenders are losing confidence in the public procurement programme, REIPPP, due to postponements. Developers invest significant 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 applications for Eskom's Budget Quote process:** due to the significant growth in renewable energy projects competing for grid capacity and grid connectivity, Eskom has become inundated with BQ applications, and this has resulted in numerous projects not being able 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 BQ is approved by Eskom.
- **Income Tax Act 58 of 1962, as amended (ITA), Section 23M limitation on the deductibility of interest on debt:** because of the interconnectedness of finance arrangements which pension

funds enter into, Section 23 M of the ITA limits the deductibility of interest expense on such financing arrangements and as a result deters pension funds from investing in certain debt funding instruments which fund energy infrastructure in South Africa due to the unattractiveness of the limitation on the deductibility of interest expense.

- **Lack of clarity for transmission energy infrastructure policy and framework:** Energy generation investment has been a key focus in the recent past within the South African market and as a result, development of transmission policies and procurement have lagged, creating a bottleneck for the rollout of further utility scale renewable energy. As a result, there have been less opportunities to fund transmission energy infrastructure. Furthermore, the lack of clarity for transmission energy infrastructure policy and framework would most likely increase the funding gap on energy generation investments due to the inability of connecting such projects to grid infrastructure.
- **Lack of ability to execute construction of renewable energy projects:** there is a shortage of key resources such as advisors and technicians in the South African market which has resulted in less projects reaching financial close and commercial operational date, thereby reducing the quantum of debt funding allocated to energy infrastructure within the South African market. As an example, due to the lack of focus on transmission infrastructure in the recent past, many of the transmission-focused EPCs either closed down or shifted focus which may result in an initial skills deficit, that is expected to be corrected over the long term.
- **Internal and external pressures from stakeholders to fund gas-to-power projects:** funders are facing pressures from internal and external stakeholders to not fund gas-to-power projects due to gas’ contribution to GHG emissions. Gas as a source of energy is crucial to balance the grid due to the increased intermittent nature of energy supply from wind and solar photovoltaic energy.
- **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 balancing act between 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 by public stakeholders:** market participants believe that there is room for improved efficiencies and coordination between the public stakeholders, which in the recent past has resulted in delays and increased costs to project sponsors. The introduction of the NTCSA with a stated objective / focus on transmission infrastructure is a step in the right direction, 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:

- **Education for private market sector and trustees of pension funds to encourage capital flows:** there is a lack of understanding and awareness on energy infrastructure investments (and their respective risk and return profiles) in South Africa, specifically within the private market sector and trustees of pension funds, which in turn 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 trustees of pension funds is a multi-faceted approach and could involve, inter alia, educational workshops and seminars, collaboration with industry experts or sharing case studies which articulate real-world examples and 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 c.R4.6 trillion, with current allocations of alternative investments to energy infrastructure making up c.2%. International norms in terms of asset allocation to alternatives and energy infrastructure is said to be around c.5%. Therefore, at an illustrative basis of 5% to 10% to alternative assets, the country could look to unlock R230 – 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 National Treasury's guarantees play a fundamental role as a credit enhancement to increasing the credit quality of Eskom. The level of guarantee provided by National Treasury is related to the appetite at which commercial banks and pension funds will fund energy infrastructure investments within the South African market. The level of National Treasury's guarantees provided to off takers has reduced as part of National Treasury's broader strategy to manage fiscal risk and ensure the sustainability of public finances.
- **Pilot projects within the transmission infrastructure sector:** given that investment within transmission energy infrastructure in South Africa is still in the initial stages, market participants believe that there is a need for pilot projects over the more immediate term to test concepts relating to funding and operating assets within this sub-sector. These pilot projects will be critical to the successful implementation of the broader transmission fundraises (i.e., independent transmission projects similar to that of the REIPPP for energy generation).
- **Development of a robust licensing and tariff regime:** particularly within transmission energy infrastructure, a robust and efficient tariff and licensing regime will be critical to building the pipeline of bankable projects. As mentioned in prior Sections, market participants have funding earmarked to be allocated to this sub-sector which can be only allocated once regulatory and

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

- **Innovative funding approaches** which have not yet been considered in the South African market, which could further incentivise significant capital formation within the energy infrastructure sector:
    - **Private funding:** policy and frameworks for transmission energy infrastructure should cater for private funding to mirror what was previously done successfully for generation. This approach could unlock significant capital formation for transmission energy infrastructure investments within the South African market.
    - **Real estate investment trust vehicles for funding energy infrastructure to enable public investment and attract direct foreign investment:** a REIT vehicle for energy infrastructure can encourage additional capital formation and allocation of funds within the South African market due to the tax and liquidity advantages of such listed vehicles.
    - **EPC contractor guarantees:** Guarantees provided to EPC contractors will promote confidence post financial close and thereby provide comfort to EPC contractors to complete the construction of the energy infrastructure project.
    - **Swops on South African Rand-based lending:** derivative instruments such as swops on South African Rand-based lending could encourage foreign capital allocators to allocate funding to the South African energy infrastructure market.
    - **Longer term funding such as a 30-year loan tenor for transmission energy infrastructure:** due to the long-term nature of transmission energy infrastructure assets, longer-term funding could alleviate cash flow pressures on transmission energy infrastructure 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 in which to raise funding and operate assets which have a broader national interest, such as transmission infrastructure. A particular reference to the operating and funding model used by Lebalelo Water Users Association for the Oliphants Management Model Programme (OMMP) was mentioned.

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

- **Development of wholesale access energy market:** the wholesale access energy market in South Africa is still in its infancy stages, and development of this market would encourage additional market participation from power producers, consumers, and financial institutions. A developed wholesale access energy market would create liquidity and pricing transparency for energy traders and could allow energy aggregators to build a track record and create confidence in the energy trading market. Such development in the wholesale access energy market would allow debt funders to obtain added confidence to allocate debt funding towards energy aggregators and ultimately increase the level of market risk which energy infrastructure funders are comfortable to take on

5.6 Conclusion

For the purposes of determining the level of the Capex funding gap and with reference to the assumptions and limitations listed under Section 5.3, a total funding requirement of R100 billion per annum (R70 billion debt / R30 billion equity) until 2050 was assumed.

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, the view over the long-term (i.e., projects post round 7 of the REIPPP and current private projects in the corporate and industrial sector) is that the long-term funding gap is significant for various reasons including (but not limited to) unattractive pricing on senior debt (i.e., margins below 200 basis points on JIBAR), unreliability of the Government's energy procurement programmes and the policy stability impacting not only the pipeline of bankable projects within energy generation but also 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 the abovementioned enablers / catalysts and innovative funding solutions could go a long way in addressing the funding gap by encouraging capital formation within the South African energy infrastructure sector, however, there is acknowledgment that there will be a need for additional sources of capital (i.e., from international markets or additional local capital formation) in order to meet the projected annual c.R100bn requirements in the long term. The collaboration between the private and public sectors will be critical to ensuring that the sector is able to meaningfully draw on all available sources of capital.

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 / support from National Treasury.

It is also important to note that the market sounding and the above conclusion did not quantify Government's funding capacity specifically. 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 / 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.
- National Treasury guarantees or similar guarantee type vehicles/products (backed by Government) will assist in the formation of capital from the private sector, as well as assist in 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 institutes.
- Develop policies, frameworks and bankable commercial structure with suitable guarantees to encourage the funding and implementation of the transmission programme.
- Reindustrialisation 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 assets classes i.e., infrastructure sector, to encourage additional capital formation and allocation.
- Promote innovative funding solutions, including the private funding of transmission, REIT type vehicles, EPC guarantees, swops on ZAR based lending, longer debt tenors, alternative funding and operating models (i.e., public private collaboration).

6 Energy Infrastructure Funding Gap Estimate

6.1 Introduction

Determining the funding gap between 2024 and the long-term time horizon of 2050 is challenging due to a multitude of considerations. Firstly, the limited availability of comprehensive investment data and associated project capital and operating costs makes establishing a true, bottom-up baseline challenging to quantify. Furthermore, of the future investment data that is available, the funding allocation is not always clearly defined - in part due to limited detail regarding the project pipeline. Lastly, the complex make-up of financial structures and instruments used as funding mechanisms depending on the specific project, paired with the interplay of global and local economic and associated policy changes, ultimately results in investment requirement estimations being a moving target.

The Climate Policy Initiative (2023) quantified the most recent and comprehensive estimate of South Africa’s climate finance funding gap. According to the estimate, South Africa requires on average between R334 billion p.a. and R535 billion p.a. to achieve the NDC by 2030 and net-zero by 2050. This estimate includes funding required for all sectors, with the energy sector requiring estimated investment ranges of between R42 billion p.a. and R198 billion p.a. To tackle the issue of data quality and availability, the methodology used to quantify the estimate was a combination of top-down and bottom-up estimates, leveraging both aggregated funding requirements and project-level data. Project-level data accounted for 92% of the analysis and with the use of unique project identifiers, double counting of projects was limited.

To validate these challenges and attempt a bottom-up calculation of the funding gap, an extensive review of various public databases related to funding inventories was conducted. The public databases that were explored 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 containing statistical time series data covering a range of topics, including energy and development. The dataset for “*Mobilised private finance for development”* was explored and provides a view of historical investments from multilateral organisations, official donors, and Development Assistance Committee (DAC) countries. The data indicates what the funding is allocated to at a high-level - for example energy policy, energy generation or energy distribution. However, it is not project-specific with project identifiers and the timeframe covers 2012 up to 2023.
- The World Bank (2025) has a “*Private Participation in Infrastructure (PPI) Project Database”* that allows for custom 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 covers 2005 up to 2023.

- The IRENA (2025) has an interactive database “*IRENASTAT”* that retrieves raw data from the “*OECD DAC Statistics”* database and the “*IRENA Public Finance”* database and allows for user selection of 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 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, with the ability to analyse fund status at an aggregated level. Further, pledges to the funds can be analysed at a contributor or country level, but without data indicating the recipient. The database also details projects with information on the funder, implementing agency, recipient institution, and what the funding is allocated to with respect to renewable energy generation. This database retrieves raw data from the “*OECD DAC Statistics”* database and reflects up to year 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 omitting important detailed information like project identifiers, names or descriptions as to what the funding was allocated to. 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 report 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 the current public spending on energy infrastructure (inferred by historical spending, where possible), and the financing requirement ranges obtained from the technical modelling performed.

6.2 Methodology

As a starting point, the methodology used is based on the outcomes of this report’s technical modelling component (Section 4) informing the finance required, and the market sounding component (Section 5) partly informing on the private sector’s ability to provide funding. The methodology is expanded by re-viewing, at a high level, the potential for public sector funding over the period as well as other forms of secured funding.

Overview of the estimation approach

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

- Capital expenditure per year including grid costs, and
- Operational expenditure per year which includes variable and fixed costs.

While the operational costs are indicated in the final calculations, it does not form part of the finance required calculation as this is deemed to be covered by adequate tariff setting and collections. While this topic will be explored in more detail, it is important to note that the focus is on the Capex funding gap.

The Capex funding gap is estimated as the difference between the capital requirement scenarios respectively, and the estimation of available funding from public and private sources over three defined periods (which is explained later in this Section) 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

In the World Energy Investment report published by the IEA (2021), it was highlighted that investment in clean energy needs to rapidly increase to meet the future energy demands. Since then, investment in clean energy (IEA 2023), has increased, but not proportionately, with only a handful of developed countries accounting for the rapid rise. To illustrate this disparity, the IEA (2023) reports that developing and emerging economies only account for one fifth of the global clean energy investment despite accounting for two thirds of the global population, with the report estimating that investment in these economies needs to increase by more than seven times to meet net-zero 2050 targets. 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 historical public sector capital infrastructure spend has averaged 3.58% of GDP between 2020 and 2023. As a proportion of this, public sector energy infrastructure investment has averaged 0.62% of GDP (National Treasury, 2024). Looking forward, South Africa's 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 GDP.[37] Considering that South Africa's public sector energy infrastructure 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 GDP by 2026. Public sector electricity investment expenditure is therefore estimated to be an average of R 45 billion per annum 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 R 112 billion in the first 5-years, of which 80% (R85.6bn) is estimated for the capacity expansion portfolio including EAs, land and servitudes acquisition. The TDP 2024 indicates that adequate capital budget (R 112 billion) has been approved and secured for the first 5-year horizon of the TDP, but that the bulk of the capital spend is expected in the later 5-year period (Eskom-NTCSA, 2025).

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

- Private Sector Participation (PSP) through ITPs. A pilot ITP project is being developed in collaboration with the Ministry of Electricity and Energy and National Treasury to test private sector involvement.
- Hybrid delivery models such as EPCM, EPC, and Owner's Engineer approaches, and
- Cost-reflective tariff structures and capitalisation policies to ensure financial sustainability.

However, from these statements, it is not yet clear how much of the funding will need to stem from public sector funding (Eskom-NTCSA, 2025).

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 (only allowing the expansion of transmission and distribution capacity) up to 2026.

Furthermore, the World Bank (2025) reported that 93.4% of rural South Africa has access to electricity as of 2022. 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

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

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. It should be noted that public sector electricity infrastructure spend must make considerations for ensuring that rural South Africa achieves full access to electricity. However, beyond that, considerations should also be made for enhancing access to electricity 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, notwithstanding potential execution risks, is noted. However, given the other constraints discussed, it is assumed that only 10%, or R 4.5 billion (in 2024 real terms) of the current budget of the Eskom group is spent on new transmission and distribution infrastructure. Beyond 2026, the assumption of 10% could potentially increase should the NTCSA strengthen its balance sheet and meet the obligations of the Eskom Debit Relief package. However, municipal compliance to the programme has been low, with only 10 municipalities honouring their current accounts by November 2024, representing only 2% of the arrear debt balance (Eskom, 2024b).

While this situation could change in the future, it is evident that domestic public sector investment will not be significant in comparison to the private sector investment needed to meet the total annual capital investment requirements to fund the JET-IP between 2024 and 2050. Furthermore, it is assumed that private sector investment will be allocated towards energy investments that have sizable benefits. Therefore, to incentivise investment, there is an urgent need for public-private partnerships (PPPs) 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 Independent ITPs previously mentioned, or concessions.

IPG grant

The Climate Funds Update (2024) established a database that consolidates cumulative data on the recipients of climate finance from multilateral climate change funds, such as the Clean Technology Fund (CTF) and the Global Environment Facility (GEF5). Filtering for recipient (South Africa) and related subsector (Energy generation, distribution and efficiency – general, power generation/renewable sources, solar energy, wind power, biomass and energy efficiency), the amount of funding approved for South Africa between 2009 and 2019 for distinct projects totals USD 576 million, of which USD 528 million is in the form of concessional loans, and the remaining USD 48 million, as grants.

Looking forward, the Presidency (2023) published an estimation of financing the JET-IP for the period of 2023 to 2027. The financing target of R 1 030 billion for the transformation of the electricity sector still requires R 315 billion (30%) as an outstanding funding gap. For the funding of the remaining R 715 billion

(70%), the JET-IP indicates that this would need to stem from a combination of funding sources including public DFIs/MDBs (R 100 billion), private sector (R 500 billion), and IPG grants (R 115 billion).

Formally, USD 6.9 billion (R 103.5 billion) of the total allocation is towards electricity infrastructure from 2023 to 2027 as stipulated in the Just Energy Transition Investment Plan (JET IP) 2023 - 2027 (Presidency, 2023). However, this analysis shows that only about 15% of these funds are allocated directly in support of capital expenditure on new generation, transmission, and distribution capacity. Following the withdrawal of the US commitment in early 2025, the European Union has indicated that it will step in to fill the gap, announcing a € 4.7 billion (approximately USD 5.1 billion) investment package to support South Africa's green energy transition. This funding will cover various projects, including renewable energy, green hydrogen production, and critical infrastructure development (ESI Africa, 2025).

Estimated private finance availability

As a starting point, the notional average annual amount of R 100 billion from the market sounding component of this report was utilised. This figure approximated the finance 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 but could expect to experience a funding gap after 2027, mainly due to a lack of project pipeline and attractive finance opportunities disincentivising private investment.

Given these indicated time horizons, and keeping in step with the technical modelling periods of five-year increments (2025, 2030, 2035, and so forth until 2050), 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 in that 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 a quantitative view on the expectation of the market sounding participants (financiers) of a gradual to significant funding gap to appear over time.

Based on the literature review, it was established that the PCC quantification of funding received follows the report and associated methodology published by the Climate Policy Initiative (2023) on the South African Climate Finance Landscape. It reports an average of R 131 billion from 2019 to 2021 from public and private sources for uses of mitigation, adaptation and dual benefits. Segmented for clean energy and energy efficiency investment only, the R 131 billion reduces to R 102 billion. Furthermore, it is assumed that the Climate Policy Initiative's quantification of funding for periods 2017/18 to 2019/21 includes the funding recorded in the Climate Fund Update (2024) database. Lastly, in addition to the amount of R 102 billion, it is recognised that the IPG loan of R 5 billion per annum from 2024 to 2026 separately, considering that the pledge came after the Climate Policy Initiative's quantification of funding received for clean energy and energy efficiency investment only. By increasing the R 102 billion amount by inflation from 2021 to reflect 2024 prices, the figure used in the calculations comes to R 118 billion.

A point on tariffs

As another stream of funding, electricity output multiplied with average electricity tariff was considered to determine an annual electricity revenue. Coming into effect 1 January 2025, the Electricity Regulation 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 preceding regulations around price setting, must be followed by NERSA who approves all electricity tariffs. NERSA's regulatory oversight 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, 2022). These costs include:

- Capital cost to generate power and equipment used: 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: varies per energy technology with solar, wind, and hydroelectric having minimal or zero fuel costs, and
- Cost of operating and maintaining the power station or plant: this includes maintenance, labour, and administrative expenses.

It remains that the government entities and associated municipalities, in accordance with the Municipal Systems Act (Republic of South Africa, 2000) and the Municipal Finance Management Act (Republic of South Africa, 2003), are not allowed to make a profit through the sale of electricity. Further, as guided by the National Treasury (2023), Eskom's capital expenditure is restricted to transmission and distribution only, whilst the Eskom Debit Relief period is active. Therefore, it is certain that any surplus of profit arising from public sector electricity sales will not be used to fund greenfield infrastructure projects related to energy generation, and any profit arising from the surplus of electricity tariffs will be limited in its impact to fund greenfield infrastructure projects related to transmission and distribution. Further, the government needs to make financial provisions for the adaptation and decommissioning of coal plants, although investment will be required from both public and private sector.

However, the new provisions have a different impact on private companies, which in part can incentivise additional funding from the private sector. Private companies selling electricity will be able to make a profit on the basis that NERSA approves tariff margins that are reasonable to enable a full recovery of investment costs but remain fair for the consumer. However, this does not guarantee reinvestment by the private company into new generation or transmission electricity infrastructure.

While Eskom does earn income from tariffs, they are owed R 110 billion by municipalities, who in turn, are owed approximately R 350 billion by ratepayers (BusinessLive, 2024). This restricts Eskom’s ability to reinvest tariff revenue into new electricity infrastructure.

Tariffs are therefore not included as a source of finance for new generation, transmission, and distribution in the funding gap calculation.

6.3 Assumptions and Limitations

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

- 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 2024 NT medium term budget.
    - The proportion of energy spending allocated to electricity generation, transmission, and distribution spending is assumed at 70% and kept constant until 2050. This equates to an average of R 45 billion over the period 2024 to 2026.
    - Energy spending as a proportion of Nominal GDP to 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 generation, transmission, and distribution is 10% of total electricity spend from 2025 to 2027 (R 4.5 billion on average) and 15% from 2028 to 2030 (R 7.5 billion on average). From 2031 to 2050, this increases to 20% (averaging approximately R 10 billion per annum).

- Private sector funding
    - Using the 2019/21 annual tracked finance of R 102 billion per annum for South Africa as a basis for estimating its value in 2024, 5% is applied for inflation per annum to arrive at R 118 billion of private sector funding available.
    - For 2025 – 2027: the figure of R 118 billion is applied for both the low and the high funding attraction alternatives. The high and low funding attraction alternatives are not applied so as not to distort the short-term view further from the range provided by the technical modelling scenario outputs.
    - For 2028 – 2030: In the low funding attraction alternative, the ability to secure 67% of the R 118 billion, equating to R 79 billion, is assumed. In the high funding attraction alternative, the ability to secure 75% of the R 118 billion, equating to R 89 billion, is assumed.
    - For 2031 – 2050: In the low funding attraction alternative, the ability to secure 50% of the R 118 billion, equating to R 69 billion, is assumed. In the high funding attraction alternative, the ability to secure 60% of the R 118 billion, equating to R 81 billion, is assumed.
- IPG loans
    - Through an extensive review of the JET-IP funding allocations, R 5 billion in 2024 real terms of funding per annum between 2025 and 2027 towards new generation, transmission, and distribution, is assumed. It is also assumed here that the EU's additional funding pledge will replace the US's cancelled portion. The IPG loan is excluded from the R 118 billion quantified as private sector funding by the Climate Policy Initiative as the IPG loan was announced after their quantification.
    - In addition, it is assumed that the Climate Policy Initiative's quantification of funding for the period 2017/18 to 2019/21 captures the funding recorded in the Climate Fund Update (2024) database.
- To summarise the above assumptions, the estimated annual average funding availability over the three periods is presented in the table below.

Table 32: Funding Attraction Alternatives per Period (R' billion p.a., 2024 prices)

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 technically allow the recovery of Opex costs and pay back 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 generation or transmission electricity infrastructure.
  - Even with NT funding and tariff revenues, the following areas place a burden on Eskom's finances:
    - Eskom's' current debt burden (including money owed by municipalities and rate payers),
    - Requirements to fund operations and maintenance on its current fleet, and
    - Costs associated with the decommissioning and/or retrofitting of coal plants.
  - Tariffs are therefore not included as a source of finance for new 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 costs for Capex and Opex were applied from 2025 to 2030 on the funding gap periods 2025 to 2027 and 2028 to 2030, and the annual average

costs for Capex and Opex of 2031 to 2050 to the third period to allow more specificity per period (i.e., the short- and medium term versus the longer term).[38]

- The table below provides a summary of the technical modelling results utilised in the funding gap estimations.

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

Scenarios		**Scenario A (Green Industrialisation)**		**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**	191.2	140.9	85.9	133.3	120.1	169.8
	Grid	35.5	35.5	24.2	24.2	21.4	21.4
	Total	226.6	176.4	110.2	157.5	141.5	191.1
	% of GDP	3.1%	2.4%	1.5%	2.2%	1.9%	2.6%
Opex	**Variable cost**	90.1	50.0	115.0	173.4	145.4	205.4
	Fixed costs	70.6	81.0	64.6	56.7	65.0	59.5
	Total	160.7	131.0	179.5	230.1	210.5	264.9
	% of GDP	2.2%	1.8%	2.5%	3.1%	2.9%	3.6%
Combined	**Grand Total**	387.3	307.4	289.7	387.6	351.9	456.1
	% of GDP	5.3%	4.2%	4.0%	5.3%	4.8%	6.2%

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

6.4 Results

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

The table below 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 2025 to 2030 and 2031 to 2050 are highlighted in the first rows. This is followed by the Capex secured and Capex (funding) gap for each period, scenario, and Capex funding attraction alternative. For clarity, Scenario A relates to the Green Industrialisation scenario, Scenario B to the Market Forces scenario, and Scenario C to the Business-as-usual scenario.

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

Table 34: Capex Funding Gap Estimations per Scenario and Funding Attraction Alternatives[39] (R' billions p.a., 2024 prices and % of GDP)

	Scenario A (Green Industrialisation)		**Scenario B (Market Forces)**		**Scenario C (Business-as-usual)**	
Capex requirement 2025 - 2030	226.6		110.2		141.5	
Capex requirement 2031 - 2050	176.4		157.5		191.1	
2025 - 2027	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**	**Low (100%)**	**High (100%)**
Capex secured	127.6		127.6		127.6	
Opex	160.7		179.5		210.5	
Capex gap	99.1		-17.4		13.9	
Gap % of GDP	1.35%		-0.24%		0.19%	
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	160.7	160.7	179.5	179.5	210.5	210.5
Capex gap	140.0	130.6	23.6	14.1	54.9	45.4
Gap % of GDP	1.91%	1.78%	0.32%	0.19%	0.75%	0.62%
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	131.0	131.0	230.1	230.1	264.9	264.9
Capex gap	107.3	95.5	88.5	76.7	122.1	110.3
Gap % of GDP	1.46%	1.30%	1.21%	1.05%	1.67%	1.51%

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[39] *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.*

For the first period, 2025 to 2027, a high and low funding attraction alternative was not calculated so as not to distort the short-term view further from the range provided by the technical modelling scenario outputs. During this period, Scenario A (Green Industrialisation) has an annual average funding gap of R 99.1 billion (1.35% of GDP), with a gap of R 13.9 billion (0.19% of GDP) in Scenario C (Business-as-usual), and no funding gap in Scenario B (Market Forces). This can be seen in the figure below.

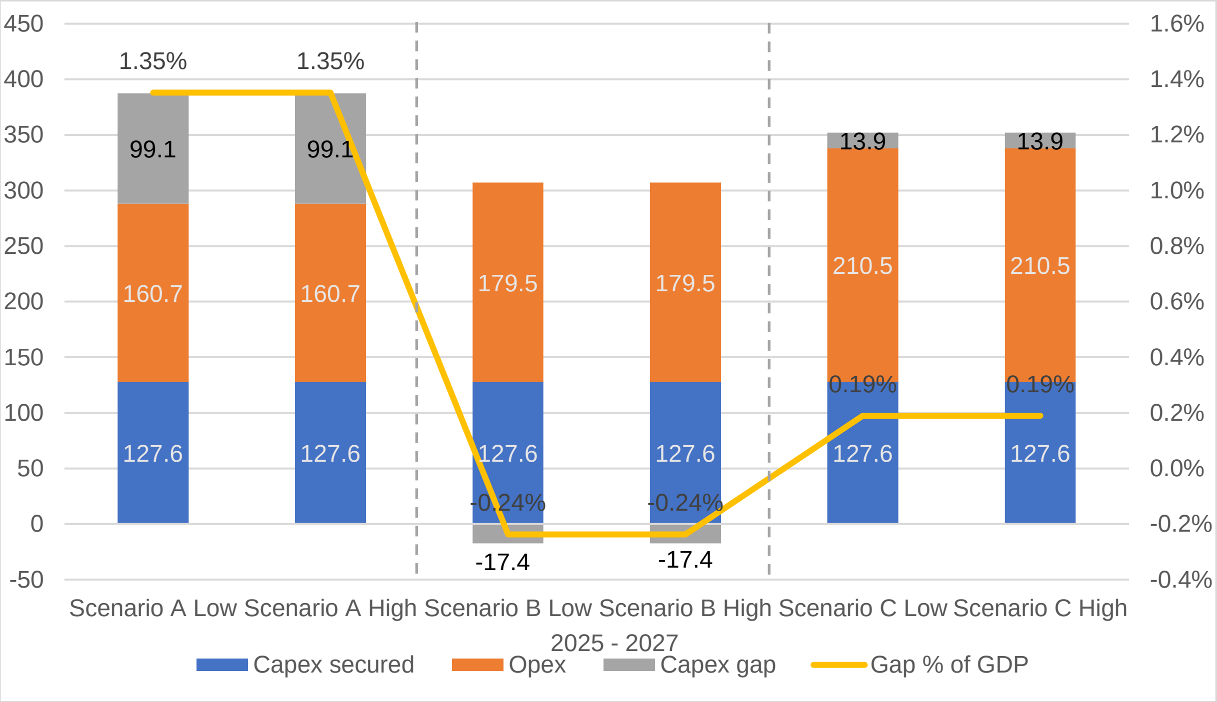

Figure 51: Capex Secured, Opex, and Capex Gap (R' billion p.a., 2024 prices), 2025 to 2027

For the period 2028 to 2030, the funding gap estimates increase from the previous period across all six scenarios. This is mainly due to the assumption that private sector funding availability will diminish under both the low (only securing 67% of the 2025 to 2027 period funding) and high (securing 75%) funding attraction alternatives. The gap over this period constitutes a wide range of R 14.1 billion (Scenario B High) to R 140.0 billion (Scenario A Low) in 2024 prices. This can be seen in the figure below.

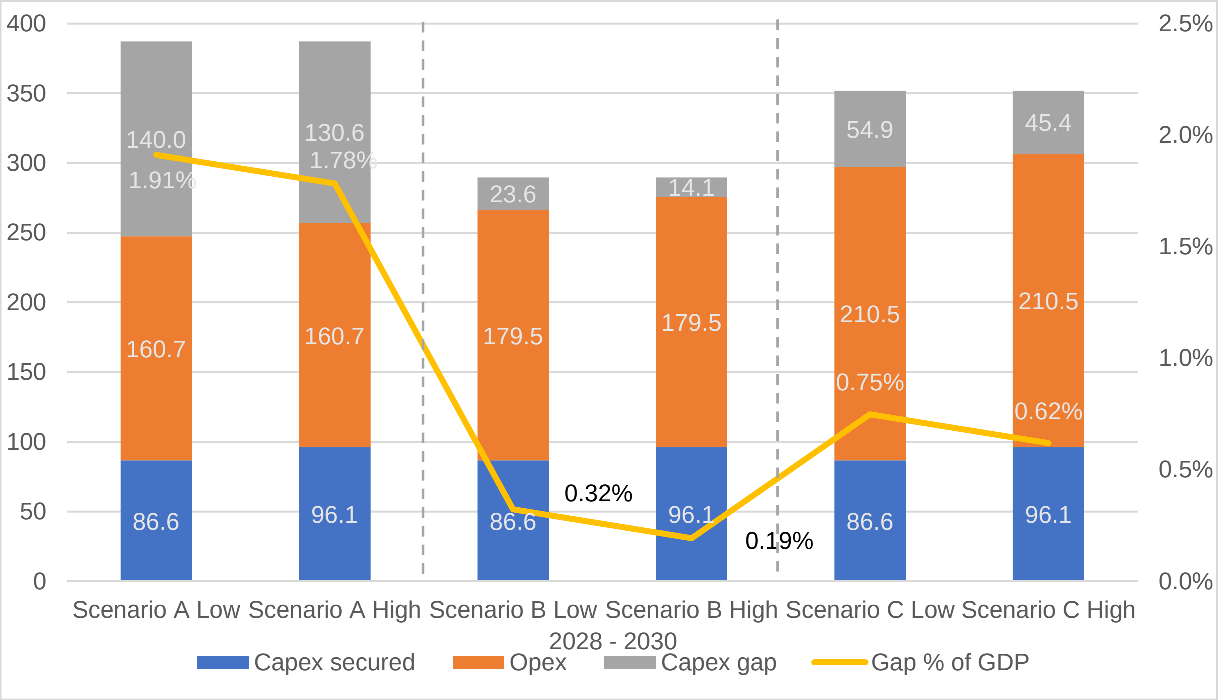

Figure 52: Capex Secured, Opex, and Capex Gap (R' billion p.a., 2024 prices), 2028 to 2030

For the period 2031 to 2050, the annual average funding gap increases further in Scenario B and C due to the same reasons established before. It was assumed that private sector funding availability will decrease further under the low funding attraction alternative (only securing 50% of the 2025 to 2027 period funding) and high alternative (securing 60%). Due to a reduction in the annual average Capex requirement during this period, Scenario A's funding gap reduced from the prior period. The minimum average annual funding gap increases to R 76.7 billion (Scenario B High) and maximum to R 122.1 billion (Scenario C Low), ranging between 1.05% to 1.67% of GDP in 2024 prices. This can be seen in the figure below.

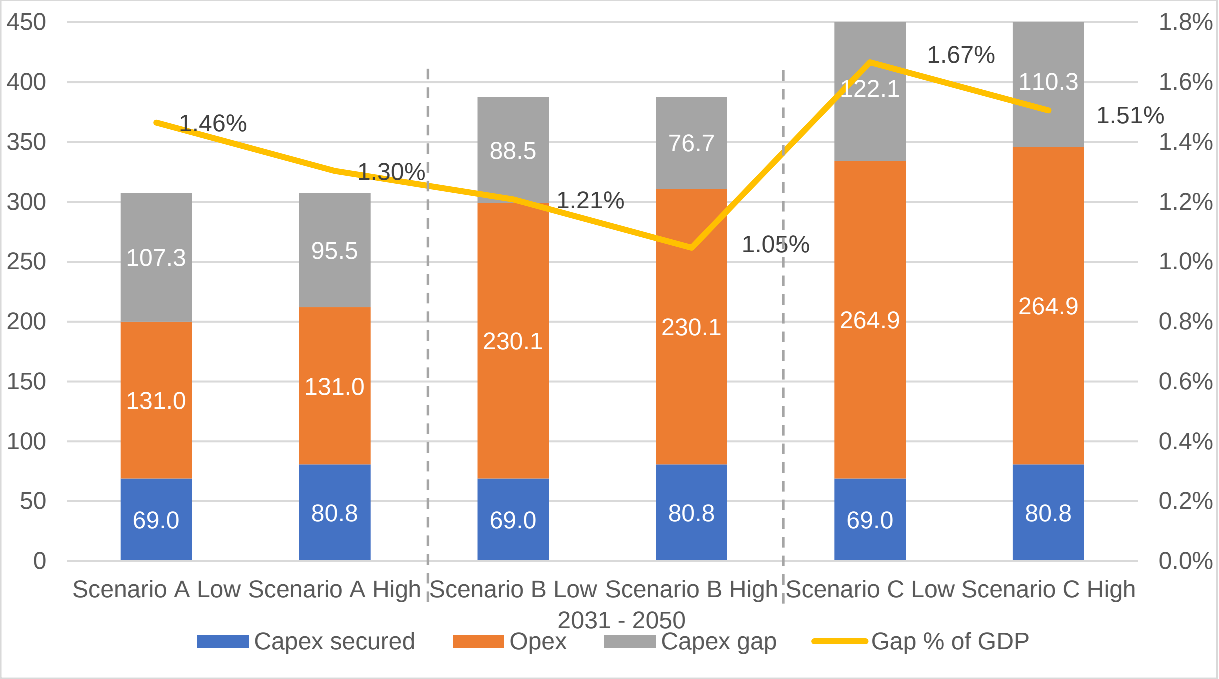

Figure 53: Capex Secured, Opex, and Capex Gap (R' billion p.a., 2024 prices), 2031 to 2050

6.5 Results Discussion

In answering the funding gap question, reliance was placed on insights from the soft market sounding exercise as well as current public and private spending on energy infrastructure, as well as the Opex and Capex financing requirement ranges obtained from the technical modelling performed.

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 market sounding participants (financiers) indicating that they expect private sector funding to be at “adequate levels” (with an annual average of R 100 billion used as the notional figure) in the short term (2025 to 2027), but that it would reduce in the medium term (2028 to 2030) and even more so 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 real 2024 prices.

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' billion p.a., 2024 prices, unless indicated otherwise)

	Scenario A (Green Industrialisation)		**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	99.1		-17.4		13.9	
Gap % of GDP	1.35%		-0.24%		0.19%	
2028 - 2030	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**
Capex gap	140.0	130.6	23.6	14.1	54.9	45.4
Gap % of GDP	1.91%	1.78%	0.32%	0.19%	0.75%	0.62%
2031 - 2050	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**
Capex gap	107.3	95.5	88.5	76.7	122.1	110.3
Gap % of GDP	1.46%	1.30%	1.21%	1.05%	1.67%	1.51%
Total Capex gap	2 863.6	2 599.1	1 788.1	1 523.6	2 647.6	2 383.1

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 are directly determined by the Capex requirements. Specifically, the timing of Capex outlay requirements for the underlying technology mix and the associated learning rates of these sets of technologies. Scenario B (Market Forces) shows the lowest overall Capex funding gap, with Scenario A (Green Industrialisation) and Scenario B (Market Forces) in line with one another. However, from 2025 to 2030, the annual average Capex outlay for Scenario A is much higher than for Scenario C, which could challenge the country’s ability to secure these levels of funding in the short to medium term.

The funding gap calculations suggest that even in the short term (2025 to 2027), with an estimated annual average R 127 billion of public and private funding secured, a significant Capex gap remains under Scenario A (Green Industrialisation) of R 99 billion per annum. With a comparatively lower Capex outlay, Scenario B (Market Forces) indicates adequate funding availability. Given the inclusion of grid costs as part of the Capex, Scenario C (Business-as-usual) also indicates an annual funding gap of R 14 billion.

For the second and third periods, the Capex funding gap expands across all scenarios as private sector funding diminishes. The Capex funding gap increases from an annual average of around R 32 billion across the three scenarios during 2025 to 2027 to R 68 billion during 2028 to 2030, and finally to R 100 billion during 2031 to 2050. The average annual Capex funding gap for Scenario A reduces in the third period compared to Scenario C, but is still higher than Scenario B.

The Capex funding gap estimations rely on the assumption that effective tariff setting and collections ensure that operational and maintenance spending is recovered over and above the repayment of Capex over the predetermined period (i.e., the Weighted Average Cost of Capital).

NERSA on 30 January 2025 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, it is noted that 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 and/or plants, there is a distinct risk that the funding gap could grow wider. The same applies to the NTCSA with respect to expanding, operating and maintaining the transmission system.

On the topic of collections, as previously noted, Eskom continues to struggle with non-payment with debt of approximately R110 billion, which could further negatively impact the long-term funding gap.

When including Opex in this equation, the gap increases to between 2.21% and 3.60% of GDP during the period from 2025 to 2027 and 2.93% and 5.28% during the period from 2031 to 2050. From 2031 – 2050, Scenarios A’s Opex is much lower than the Opex of the other two scenarios, which leads to this scenario having the lowest total funding gap over the full period. This is captured in the table below.

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

	Scenario A (Green Industrialisation)		**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	259.7		162.1		224.3	
Gap % of GDP	3.55%		2.21%		3.06%	
2028 - 2030	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**
Total gap	300.7	291.2	203.1	193.7	265.3	255.9
Gap % of GDP	4.10%	3.98%	2.77%	2.64%	3.62%	3.49%
2031 - 2050	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**
Total gap	238.3	226.5	318.6	306.8	387.0	375.2
Gap % of GDP	3.25%	3.09%	4.35%	4.19%	5.28%	5.12%

The calculations are very specific to new energy generation, transmission, and distribution infrastructure and therefore can’t be directly compared to many other studies. While most studies provide estimates on the funding need to build new generation, transmission, and distribution, 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 R 315 billion (USD 21 billion) or around 25% against the total JET-IP investment needed between 2023 to 2027.

The PCC (2023a) 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 R 203 billion to R 404 billion per year is outstanding and necessary to meet the NDC goals. However, this needs qualification as it extends beyond new generation, transmission, and distribution infrastructure requirements. The PCC (2023b) found that within the energy sector, investment requirement estimates range from a minimum of R42 billion p.a. to a maximum of R198 billion p.a., with an average investment need of R111 billion p.a. The study stopped short of attributing an estimated funding gap directly to the energy sector.

The NBI (2022) articulates that while approximately R 70 (USD 4.67) billion per annum has already been mobilised for energy sector transformation, an average gap of R 140 (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, it covers investment over and above energy infrastructure investment without allocating a specific funding gap.

6.6 Conclusion

The Capex funding gap estimations suggest that even in the short term (2025 to 2027), a notable (under Scenario C – Business-as-usual) to significant (under Scenario A - Green Industrialisation) Capex funding gap could exist.

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

This analysis indicates that available public energy infrastructure spending or Eskom tariff revenues will not be adequate to finance the required new generation, transmission and distribution infrastructure. Therefore, funding would need to be sourced from the private sector (including donor funding).

The market sounding participants (financiers) detailed that regulatory and project (supply) challenges could lead to diminishing private sector funding in the medium and longer 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 investible energy infrastructure projects.

6.7 Recommendations

Overarching interventions to secure additional private sector funding would be to:

1) Expedite regulatory and market reform (market code).
2) Look at mechanisms to develop and attract the necessary technical and deal-making skills to allow additional, investable project pipeline beyond the short term.

3) Effectively and strategically use (catalytic) public sector funding or guarantees to increase project attractiveness by reducing risk. This, together with a predictable regulatory environment, can increase investor confidence and leverage additional capital though Public-Private Partnerships, Blended Finance, and 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 and related to funding energy infrastructure in South Africa. It further aims to offer concrete recommendations for regulatory improvement and reform towards reaching a competitive, resilient, and sustainable electricity sector based on the funding gap and modelling outlined in the earlier Sections.

7.2 South African Analysis

7.2.1 The Constitution

The Constitution makes no mention about 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 can be implied 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.
- Secure ecologically sustainable development and use of natural resources 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 like solar, wind, and hydro, 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 is echoed in Section 237 of the Constitution that provides that "[a]ll constitutional obligations must be performed diligently and without delay." These services include electricity reticulation and providing electricity and is therefore an important funding source for local governments, particularly for larger urban municipalities. As such, it is imperative that government has the necessary legislation and policies in place to achieve the constitutional provisions related to electricity provision. 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	The White Paper on Energy Policy is South Africa’s overarching document which sets out the government’s official policy on the production, distribution, and consumption of energy. In a general sense it represented, for the first time, a comprehensive and holistic perspective of South Africa’s official overall energy needs and options and laid the foundation for energy laws such as the National Energy Act and the Electricity Regulation Act. The White Paper’s initial commitment to renewable energy technologies was supplemented by a specific policy document on renewable energy known as the White Paper on Renewable Energy of 2003. The paper also discusses the development of a national electrification strategy. The government will ensure the allocation of funds for addressing backlog electrification projects and will aid in subsidising infrastructure developmental 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 backlog and electrification as part of new infrastructure development for funding purposes.[40] 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 curtailing 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. [41] Whilst the White paper dates to 1998, its principles echo with the current transition being experienced in the South African energy sector and its aims remain relevant to guide the process of liberalisation.
The South African Renewable Energy	The South African Renewable Energy Masterplan (SAREM) was adopted by the South African cabinet on 28 March 2025. It aims to industrialise and localise the renewable

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[40] *See p48 of the White Paper.*
[41] *See p48 of the White Paper.*

Policy	Provisions in policy relating to the financing of energy infrastructure
Masterplan (adopted by cabinet on 28 March 2025)	energy 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 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.[42] ● **Strategic Partnership Programme (SPP):** Launch and progressively expand the SPP to incentivise large private-sector enterprises to support and develop the ability of SMMEs within their supply chain. The SPP is a cost-sharing programmes 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 localisation objectives into public procurement programmes from all spheres of government and state organs. Additional and/or more advantageous support should be awarded to beneficiaries procuring locally, ensuring that public policy related to renewable energy and storage aligns with localisation 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 Energy

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[42] *See p50 of the SAREM.*

Policy	Provisions in policy relating to the financing of energy infrastructure
	Development Zones and focusing on regions like Mpumalanga where 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 formalised or introduced and the development and implementation of these initiatives would have to be sped up to increase the deployment of renewables as envisioned under the masterplan.
National Integrated Energy Plan (IEP) 2016	The development of a National IEP was envisaged in the White Paper on Energy Policy of 1998 and, 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 emerged since its publication. The plan does not outline specific plans in relation to the funding of electricity infrastructure but rather highlights certain funding needs. Some of the funding needs are outlined below: ● 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 Department of Electricity and Energy to ensure that their mandates are achieved.

Policy	Provisions in policy relating to the financing of energy infrastructure
	● Funding should continue to be provided to ensure the implementation of the INEP and the Universal Electrification Strategy. ● Funding should also be allocated for the development of an Integrated Household Energy Strategy. ● Investment in R&D to find innovative means for the beneficiation/recycling of gases emitted in the generation of electricity. ● Large investments in transmission lines are necessary from the areas of high radiation to the main electricity consumer centers to enable increased solar deployment. ● The current policy and regulatory framework could be developed, 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 Energy Plan that sets out South Africa’s Energy Roadmap. The IRP is a National Electricity Plan and can be seen as a subset of the 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 and abundance of coal. ● The enablement and acceleration of enabling and acceleration of private investment in power generation capacity. ● The need to address Eskom’s debt to unlock much-needed investment in critical transmission and other infrastructure, and 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 decarbonisation of the electricity sector, promote new economic opportunities such as green hydrogen and EVs, and ensure that the transition is just, protecting vulnerable workers and communities affected by

Policy	Provisions in policy relating to the financing of energy infrastructure
	the shift away from coal. The plan outlines key financing mechanisms needed to fund the JET. These include the following: 1) **Grants**: Grants are effective in strengthening the enabling environment for priority sectors and supporting critical non-revenue generating initiatives such as policy development, capacity building, developing sector strategies, and feasibility studies. As such, grants can be used to create an enabling policy environment to attract additional funding and investment from the private sector. 2) **Concessional loans:** When strategically deployed, concessional financing is a catalytic source of funding by being able to mitigate real and perceived risks, lower 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 GH_2 sectors. • **Budgetary support:** Budget resources will need to 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 mobilise. • **Blended finance**: Budget resources will need to 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 mobilise. 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 risks-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; along with equity as a source of

Policy	Provisions in policy relating to the financing of energy infrastructure
	subordinated, risk-sharing capital that can accelerate growth and enable addition leverage to flow into 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-emission economy. It highlights the role of public-private partnerships (PPPs) in mobilising 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, to drive infrastructure expansion. The strategy acknowledges the importance of International Climate Finance to support its 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 effectively access and deploy these funds. 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 mobilising 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 (NIP, 2022) 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 National Development Plan's vision of inclusive growth. Section 4 of the plan specifically outlines financing elements to deploy and maintain infrastructure. The NIP 2050 outlines provisions for the funding of energy infrastructure in the following ways: • Government and Public Investment • The plan highlights the role of government funding in strategic energy projects, including renewable energy, grid expansion, and modernisation. It also

Policy	Provisions in policy relating to the financing of energy infrastructure
	allocates resources for state-owned enterprises (SOEs) to improve energy generation and transmission capacity. • Private Sector and Public-Private Partnerships (PPPs) Emphasises leveraging private sector investment through regulatory incentives, tax benefits, and co-financing models. It also encourages independent power producers (IPPs) to participate in electricity generation, particularly in renewables. • International and Development Finance Aims to secure funding from multilateral development banks, international climate finance mechanisms, and foreign direct investment (FDI). The plan also prioritises grants and concessional loans for green energy projects. • Tariff Adjustments and Cost Recovery Proposes reformation in energy pricing to ensure 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 decentralised, modern, and low-carbon energy system enabling vital reforms that will accelerate financing of the JET – which 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: The Act also envisions creating a Central Purchasing Agency 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. However, the Act does not specify how the day-ahead market will be housed, set up, or operated. However, 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 decentralisation and liberalisation of the market resulting from the Act will lead to greater policy and regulatory certainty, which will drive investor confidence.
National Energy Act, 2008 (Act No. 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 research and development. The Act does not outline any specific financing provisions in relation to energy infrastructure, however it must be noted that Section 19 of the act enables the Minister of Mineral Resources and Energy to make regulations regarding "measures and incentives designed to promote the production, consumption, investment, research and development of renewable energy",[43] "measures to ensure adequate provision of energy related Infrastructure;"[44], and lastly measures to "promote security of supply through access to common infrastructure by any party, where not provided for under any other legislation"[45]. Although these provisions have never been used, the Act offers the opportunity for regulations to be introduced, aimed at specifically aiding the increased deployment of energy infrastructure. The possible measures to introduce under these provisions are discussed in the international best practice Section below. In addition to the above, Section 18 specifically addresses "[i]investment and maintenance of energy infrastructure" and 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 doesn't directly address energy infrastructure, it plays a crucial role in shaping how public funds are allocated and managed. Section 38 requires accounting officers and accounting authorities to establish a system for evaluating all major capital

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[43] *See Section 19(1)(f) of the Act.*
[44] *See Section 19(1)(o) of the Act.*
[45] *See Section 19(1)(q) of the Act.*

	projects prior to a final decision on the project.[46] This means that when considering the procurement of energy infrastructure projects, any public sector department would have to evaluate such a project prior to making a final procurement decision. This 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 Funds 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 continues to leave the final decision on any investment to the trustees of each fund, who decide the investment policy. 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 extent, the amendments introduce a definition of infrastructure and sets a limit of 45% for exposure in infrastructure investment. To further facilitate the investment in infrastructure and economic development, the limit between hedge funds and private equity has been split. There will now be a separate and higher allocation to private equity assets, which is 15% increased from 10%. A limit of 25% has been imposed, across all asset classes to limit 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 Republic.
Income Tax Act 58 of 1962	South Africa has introduced several energy incentives in its ITA such as: **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 photovoltaic solar panels,

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[46] *See Section 38(1)(a) of the Act that provides 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."*

	wind turbines, and biomass facilities). This incentive is available for two years, 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 photovoltaic (PV) panels, up to a maximum of R15,000. The incentive was aimed at increasing electricity generation and supporting the country's clean energy transition. However, this incentive was available only for a limited period, from March 1, 2023, to February 29, 2024. However, this shows government's commitment to introduce incentives which would drive investment in energy infrastructure. **Section 12L Energy Efficiency Savings Deduction**: The ITA 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 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 socio-economic considerations in 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 adaption 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 Adaption Strategy and Plan. [47]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 energy sector Adaption Strategy still needs to be developed as part of this provision of the Act, it is likely to require increased investment in renewables as well 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 r on the

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[47] *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.*

	progress made in relation to the implementation of the relevant Sector Adaptation Strategy and Plan.[48] 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 the sectoral emissions targets, and the best available science, evidence, and information. A sectoral emission target for the energy sector would most likely lead to increased pressure to reduce emissions from fossil fuels and result in the increased investment in renewables and lower carbon sources of energy such as gas.

7.2.3 Findings Discussion on 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 like 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 backlog electrification and new infrastructure. Yet, without developed alternative funding and pricing mechanisms, the energy sector struggles with balancing cost-reflective tariffs and substantial tariffs 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, but lacks detailed financial commitments or specific mechanisms. In contrast, the NIP 2050 provides a more structured approach, detailing funding strategies such as government investment, private sector participation, international finance, and cost-recovery mechanisms to support energy infrastructure expansion and sustainability.

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[48] *Please see Section 22(1) of the Act that sets out the requirements for the sector adaption plans.*

The Electricity Regulation Act, while aimed at decentralising and modernising South Africa’s energy system, lacks explicit provisions for funding energy infrastructure. This omission creates a significant gap, as the decentralisation and liberalisation 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, 2008, does not specify financing provisions for energy infrastructure, although it empowers the Minister of Electricity and Energy to introduce regulations promoting investment and ensuring adequate infrastructure provision. However, these provisions have not been utilised, leaving a gap in the direct funding mechanisms needed 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: NDC, 2021). The guiding policies like the White Paper on Energy Policy and the SAREM to promote energy infrastructure deployment and increase the use of renewable energy. Despite these policies outlining ambitious strategic objectives, the country’s legislation lacks the necessary provisions to formalise 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 and the associated tariffs in place. This stifles 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 geared to supply the customers embedded in the municipal area of supply.

Section 7.3 below highlights international best practice mechanisms for South Africa to consider accelerating the funding of the infrastructure needed.

7.3 International Best Practice Analysis

For purposes of this report, the international best practices of multiple countries were considered, namely, Germany, the United States, and the United Kingdom and Malaysia (see Table 35 below). Lessons from other countries have also been considered where applicable. These countries were included as each employ unique best practices in energy funding mechanisms to advance their renewable energy goals. Germany's “Energiewende” (energy transition) programme is a leading example, using feed-in tariffs (FiTs) to guarantee long-term contracts and stable returns for renewable energy producers, thereby encouraging investment. The United States 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 Renewable Portfolio Standards (RPS) that mandate a certain percentage of energy to come from renewable sources. Similarly, the United Kingdom’s Renewables Obligation mechanism requires electricity suppliers to source a specified proportion of their electricity from renewable sources, incentivised 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 considered to be an upper-middle income country. Both countries rely heavily on fossil fuels, particularly coal, for their electricity generation. In Malaysia, coal accounts for about 43% of the power mix, while natural gas contributes around 47%. This is somewhat similar to South Africa, where coal dominates the energy mix. Lessons from Malaysia will also be considered.

The table below outlines some of the mechanisms which have enabled the deployment of energy infrastructure in other countries. These mechanisms are mentioned here but elaborated on 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 are to: 1) **Promote the development of renewable energy sources** to reduce GHG emissions and combat climate change. 2) **Increase energy security** by diversifying the energy supply, and 3) **Stimulate technological innovation** and economic growth in the renewable energy sector.
United States	The United States has implemented various regulatory measures to stimulate renewable energy deployment and investment. These measures include federal and state policies, tax incentives, and regulatory frameworks aimed at promoting renewable energy. **Federal measures include the ITC and the PTC discussed below.**

Country	**Energy infrastructure financing mechanisms to be considered**
United Kingdom	The United Kingdom primarily uses CfD[49] 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. to support renewable energy, providing long-term price stability by covering the difference between the market price and a pre-agreed strike price, thus reducing investor risk. 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 decentralised 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 qualifying capital expenditure 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 the aforementioned countries, four possible mechanisms are recommended below to drive energy investment and funding in South Africa. These are the following:

- 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.

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[49] *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).*

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.[50]

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 surcharge has been instrumental in financing the expansion of renewable energy capacity in Germany, leading to a substantial increase in the share of renewables in the energy mix.

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 Act.

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 the projected costs for the upcoming year, including the estimated payments to renewable energy producers and the 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. The 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

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[50] 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 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.

total electricity consumption in Germany. This ensures that the surcharge remains aligned with actual 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 sur-charges over the years, which has raised concerns about the affordability of electricity for consumers, particularly low-income households. If adopting a similar mechanism in South Africa, it would be critical to con-sider the social equity aspects of such a surcharge by ensuring that the cost burden is distributed fairly and does not disproportionately impact 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, it would not be recommended that large energy users are exempted, 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 grows, its integration into the electricity market and managing its variability becomes more challenging. The EEG surcharge needs to be complemented by in-vestments 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 the costs, enhance market integration of renewables, and promote cost-effective deployment of renewable energy technologies. In the South African context, policy adjustments are generally a lengthy process. However, if the charge is incorporated as part of the charges imposed by the Customs and Excise Act 91 of 1964, it could remove lengthy policy adjustments and administratively burdensome processes. A mechanism like the fuel levy or environmental levy can be considered and it could be administered by the South African Revenue service.

7.3.2 Renewable Energy Tax Incentives

The US’s 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 aimed at driving increased deployment of renewables and increasing generation capacity from the plants.

7.3.2.1 Investment Tax Credit (ITC)

a) Overview

The ITC is a federal tax credit designed to support the installation of solar energy and other renewable energy systems. The credit is applied to the total cost of installing the system, and it allows 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 it can 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. This means 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 manufacturing, installation, and maintenance sectors.

Box 4: 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:

- 100% tax allowance on qualifying capital expenditure incurred on green technology projects.
- The allowance can be set off against 70% of the statutory income for each year of assessment.
- The incentive period can last 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:

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

7.3.2.2 Production Tax Credit (PTC)

a) Overview

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, often 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 incentivises the efficient operation of renewable energy systems.
    - **Revenue Stream**: The PTC provides a steady revenue stream for renewable energy projects, which can improve their financial viability and attractiveness to investors.
    - **Long-Term Support**: The length in 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, making it easier for projects to get 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 there are specific rules and limitations. The ITC helps with initial investment costs, while the PTC supports ongoing energy production, creating a comprehensive support mechanism for renewable energy development.

Lessons for South Africa from the energy tax incentives in the United States

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

Similar incentives can be introduced in terms of the ITA 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 focussed on the generation elements would be beneficial given that the ITA already contains investment incentives as outlined in the assessment above. The tax credit could be similar to the PTC in the US and claimed per kWh of electricity generated by the renewable energy system. Such an incentive could be specifically useful given the fact that financiers are hesitant to invest in renewables given the low rates of returns.

7.3.3 Renewable Energy Targeting Mechanisms

Although not a specific financial mechanism, countries across the globe have adopted renewable energy targeting mechanisms mandating 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 which have successfully aided the funding and deployment of renewable energy are outlined in the table below:

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

Country	Renewable energy targeting mechanism adopted
United States	RPS are state-level policies that mandate utilities to 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 distributors - municipalities - are at various levels of preparedness when it comes to energy procurement. As such, each municipality must be given a level of discretion to develop its own targets and timelines should a similar mechanism be considered for South Africa.

	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 into 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 or to 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	The Renewables Obligation scheme in the United Kingdom 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 usually 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 that have presented ROCs, 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 is yet to become as developed compared to the models outlined above. The system currently in place in South Africa is a voluntary system and is not set out 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 to reduce their reported scope 2 emissions.

A possible new renewable energy targeting mechanism can be introduced like the international best practice mechanisms outlined above. Municipalities can be required by 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 introduced by either introducing a new law focussed 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

As highlighted in the market sounding Section, market 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 more attractive to investors to stimulate the required funding for generation energy, distribution energy, and transmission energy infrastructure. Some pricing stability and revenue mechanisms are set out below:

7.3.4.1 Capacity Markets:

In some jurisdictions, capacity markets have been introduced which 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.

7.3.4.2 Capacity Market in the United Kingdom:

Part of the government's electricity market reform package introduced in the UK, the Capacity Market ensures security of electricity supply by providing a payment for reliable sources of capacity, alongside their electricity revenues, to ensure they deliver energy when needed. This encourages investment needed 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:

- **T-4 Auction**: Held four years ahead of the delivery year. This auction secures most of the required capacity.
- **T-1 Auction**: Held one year ahead of the delivery year. This is used to fine-tune the capacity requirements based on more accurate demand forecasts.
- 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 incentivising the right mix of capacity. This in turn creates more investor confidence by removing some of the physical risks associated with grid stability.

South Africa is in the process of also 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 as part of the wholesale market include 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 availability rate, an availability penalty is applied to those power plants unable to meet their declared supply in the market.

7.3.4.3 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 stabilise the grid urging system stress events. Failure to deliver results in penalties, ensuring that participants are incentivised to perform as required.

7.3.4.4 UK's Ancillary Services Market

The UK's 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**: Ancillary services that help maintain grid frequency within the required range (50 Hz). This includes fast-acting services like Frequency Response (both Fast Frequency Response and Firm Frequency Response).
- **Reserve Services**: These are standby capacities that can be activated quickly 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 into 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 Great Britain.

In South Africa, the power required to balance the system in real time will be procured through ancillary services and Day Ahead reserve markets, where generators declare that they are available at specified times to produce a certain amount of power, if there is a shortfall. These generators will be compensated both 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 also higher making it an attractive proposition for funders.

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

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 envisaged to be higher. 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**: Design the market to ensure transparency, fairness, and competitiveness. This includes defining market rules, pricing mechanisms, and settlement procedures.
- **Incentives and Penalties:** Implement appropriate incentives for providing ancillary services and penalties for non-compliance to ensure reliability and quality.
- **Grid Modernisation:** Invest in modernising the grid infrastructure 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. A wide spectrum of options exists for these payments, categorised according to several factors, including the kind of capacity being made available, how far in the future the obligations span and how the payment costs are determined and allocated.

Although the capacity and ancillary markets are being developed under the Market Code, it is critical that the mechanisms applied in other countries be analysed with due consideration of the unique South African circumstances. Capacity payments can be made to both consumers who reduce their demand and generators who increase their supply of electricity. A wide spectrum of options exists for these payments, categorised according to several factors, including the kind of capacity being made available, how far in the future the obligations span and how the payment costs are determined and allocated.

7.3.5 Deemed Energy Payments

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

Morrocco is one example of an African jurisdiction having adopted a mechanism to address network risk. Morocco's power sector reforms have been unique, driven by strong political objectives for rural electrification and decarbonisation. 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 has maintained a strong, state-owned, vertically integrated national power utility, *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 privatising electricity distribution through concessions, involving 11 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, minimising revenue loss impacts on municipalities and enabling cross-subsidisation.

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" (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 principle defined in NERSA's Regulatory Rules should be enforced and should be legally binding on Eskom or any other NSP. This will remove one of the major risks in the project and streamline the negotiations of bilateral PPAs with wheeling enabling a sustainable in-vestment for all parties. As discussed above, a good example of such enforcement is found in Morocco where the Grid Access agreement, signed with the Moroccan TSO (ONEE) and the SPV, regulate the mechanism of the Energy Not Delivered" (or "ENL, Energie Non Livrée), as described in the box below. A similar provision/mechanism should be considered for South Africa to provide generators with greater security in case of forced curtailment from Eskom.

7.3.6 Allow Payments to IPPs Generating During Plant Testing Phase

RETEC approval from Eskom refers to the Renewable Energy Technical Evaluation Committee process. This is a critical step for renewable energy projects in South Africa to ensure 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 Eskom/NTCSA's approval post-report submission. This could amount to tens of millions of kWhs that Eskom can sell, thereby benefitting Eskom/NTCSA and incentivising RETEC to delay approvals. Additionally, this discourages the IPP from generating early energy due to the operational costs that cannot be covered 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 (AEMC, 2024).

Clause 5.7A of the Rules specifies the commissioning process for new generators, including the testing period. Generators must notify AEMO and the relevant network service provider 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, even during testing, to bid into the NEM spot market. 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 Merket Code/Rules supporting the functioning of the market must include similar provisions to create greater investor confidence based on remuneration of electricity generated during the connection phase.

7.3.7 Introduce Grid Connection Guarantees

On 6 May 2024, Eskom applied to the NERSA in terms of Section 21(2) of the ERA, 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 ERA (NERSA, 2024).[51] NERSA rejected Eskom's application based on Eskom's failure to justify 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 on which customers would be affected. This decision maintains the current "first ready, 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 might reduce the bottleneck caused by delays in the government procurement process by ensuring that only projects with confirmed grid access move forward. It would also create more 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 Act, known in German as Erneuerbare-Energien-Gesetz (EEG). By securing grid connection guarantees before bidding, the risk of over-allocating grid capacity would be minimised. This would reduce the likelihood of conflicts between REIPPP and bilateral projects. The German model has helped to 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 what TSOs do in Germany.

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[51] *National Energy Regulator of South Africa, Gird 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*

7.3.8 Findings 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 due to transparent bidding procedures. Furthermore, streamlined permitting and approval processes have been instrumental in expediting project development, reducing bureaucratic delays, and minimising regulatory uncertainty.

Another successful approach observed is the use of hybrid financing models that leverage public-private partnerships (PPPs). These models have enabled risk-sharing between governments and private investors, fostering greater capital inflows into energy infrastructure. Additionally, regulatory mechanisms that support grid modernisation 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 conducive investment climate.

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 prioritises energy infrastructure as a national strategic investment area. Currently, regulatory responsibility is dispersed across multiple departments and agencies, creating 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 hinders 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 - features that are largely missing or inconsistently applied in South Africa. Furthermore, the current procurement frameworks, such as REIPPPP, while successful in some respects, are not backed by overarching legislation that entrenches 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 mobilised 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 independent power producers (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. In many leading jurisdictions, national governments have adopted long-term infrastructure planning legislation - 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 incentivised investment through targeted fiscal instruments, including tax incentives, green bonds, and concessional financing aligned with climate and development goals.

Ultimately, the comparison highlights that while South Africa has expressed strong political commitment to energy infrastructure development, this has not yet been translated into a robust regulatory system capable of delivering investment at the pace and scale required. Without targeted reforms that 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 can also be seen as 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 between compared with 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 critical to speed up the transition to a climate-friendly future, leading to cost reductions and heightened 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 greenhouse gas 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

From this analysis, it is established that South Africa has core guiding policies such as the White Paper on Energy Policy and the SAREM which aim to promote energy infrastructure deployment and the increased utilisation of renewable energy. Although these policies outline ambitious strategic objectives, the country’s legislation lacks the necessary provisions to formalise 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 stabilise the grid, and streamline the surcharge by integrating it into existing tax systems.

Tax Incentives: Offer tax breaks like the US’s ITC and PTC to lower upfront costs and reward energy production, driving renewable energy investment and sustained growth. South Africa has introduced tax incentives for household and businesses as discussed in analysis of the Income tax Act, but incentives aimed at utility scale deployment, such as the ones 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 Renewable Energy Certificates (RECs) to ensure compliance and incentivise investments through supportive legislation.

Pricing and Returns: Create capacity and ancillary services markets to secure 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 from Eskom Distribution to the NTCSA or another independent entity: The Grid Access Unit 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 ERA principle of creating an energy market in line with international trends. This situation creates a conflict of interest for the Grid Access Unit 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 Grid Access Unit (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.

Moving the Grid Access Unit to an independent entity or the National Transmission Company of South Africa, could offer several benefits:

- **Reduced Conflict of Interest:** By separating the GAU from Eskom Distribution, the potential conflict of interest is minimised. 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. Specialised attention to grid access issues could potentially lead to more innovative and effective solutions for grid management expansion.
- **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 be moved, certain regulatory reforms might be required. In terms of the GAU's mandate, it is responsible for facilitating and managing the grid access entry of IPPs and other generators, providing holistic solutions to aptly serve their needs, 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, provides 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 the provision of access to the grid, which is the responsibility of the NTCSA. The GAU's role in facilitation and management does not equate to the provision of access. 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 Results/Findings, Conclusions and Recommendations

8 Summary of Key Results/Findings

Operating capacity

The infrastructure technical modelling identified the energy mix with the lowest investment requirement to meet the national electricity demand, based on the 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 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, also 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.

From 2030 onwards, all scenarios entirely meet the demand i.e., there is no unserved energy / load shedding observed in the results beyond 2030.

Table 41: Operating Capacity per Technology in 2030 and 2050 per Scenario (GW)

Year	Tech-nology	Scenario A (Green Industrialisation)	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

Year	Tech-nology	Scenario A (Green Industrialisation)	Scenario B (Market Forces)	Scenario C (Business-as-usual)
	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.

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 Northern Cape to Gauteng via North West and Hydra Central to Gauteng via 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 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. Scenario A’s constraint was based on meeting or beating the current NDC targets, while Scenario B’s constraint would likely result in a partial exceedance of 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 for the period from 2023 up to 2050 is shown in Figure 54. Scenario A achieves 123 Mt/a CO_2 emissions in 2030, which is generally considered to be 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).

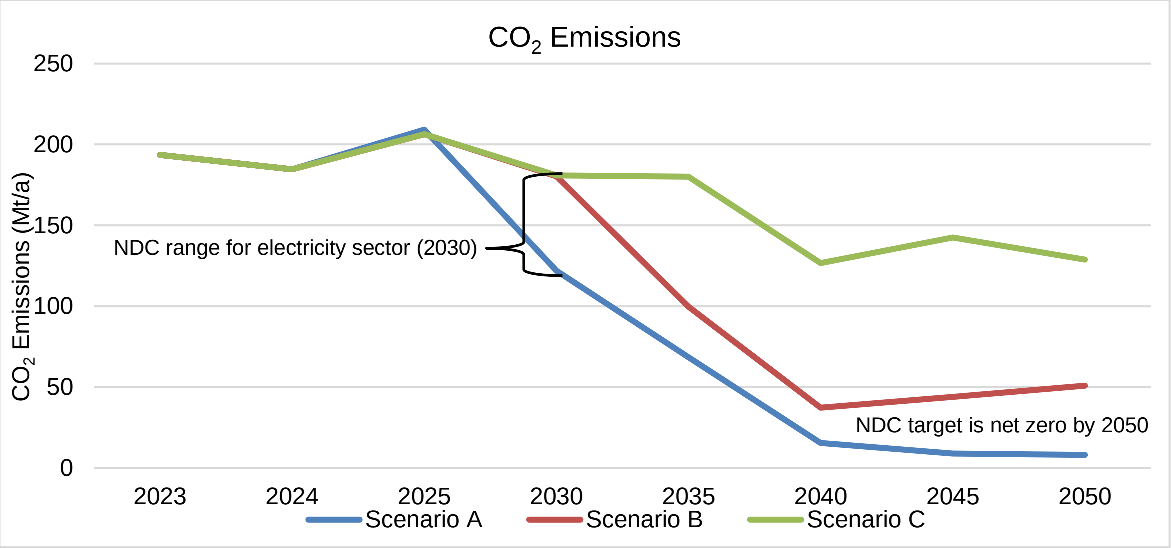

Figure 54: CO$_2$ Emissions per Scenario

Investment required

The total investment required per scenario over the period from 2025 to 2050 is shown in Table 42. Even though Scenario A requires the largest build of new generation and storage capacity, it results in the lowest total system investment due to more optimistic technology learning rates and lower variable generation costs (because of less fuel being required, combined with lower fuel prices). Scenario C, although requiring the smallest build of new generation and storage capacity, results in the highest total system investment due to least optimistic technology learning rates and higher variable generation costs.

Table 42: Total System Investment per Scenario from 2025 to 2050 (R billions, Discounted at 8% to 2024)

Investment detail	Scenario A (Green Industrialisation)	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 in the period 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.

Following this, Scenario A benefits from the lower variable generation costs, and requires the lowest average annual investment for the period from 2031 to 2050, compared to Scenarios B and C.

Table 43: Average Annual Investment per Period per Scenario (R billions, Discounted at 8% to 2024)

Scenarios		**Scenario A (Green Industrialisation)**		**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**	191.2	140.9	85.9	133.3	120.1	169.8
	Grid	35.5	35.5	24.2	24.2	21.4	21.4
	Total	226.6	176.4	110.2	157.5	141.5	191.1
	% of GDP	3.1%	2.4%	1.5%	2.2%	1.9%	2.6%
Opex	**Variable cost**	90.1	50.0	115.0	173.4	145.4	205.4
	Fixed costs	70.6	81.0	64.6	56.7	65.0	59.5
	Total	160.7	131.0	179.5	230.1	210.5	264.9
	% of GDP	2.2%	1.8%	2.5%	3.1%	2.9%	3.6%
Combined	**Total**	387.3	307.4	289.7	387.6	351.9	456.1
	% of GDP	5.3%	4.2%	4.0%	5.3%	4.8%	6.2%

Funding gap

Market sounding participants (financiers) indicated that in the short term (2025-2027), they do not expect a (Capex) funding gap for energy infrastructure investments within the South African market. However, over the medium- (2028-2030) to long term (2031-2050), their expectation is that the Capex funding gap will be significant due to various obstacles and limitations. These include (but are not limited to) unattractive pricing on senior debt, unreliability of the government’s energy procurement programmes as well as policy uncertainty and instability. The unattractive debt pricing creates a challenge with local investors and banks as they may become unable to syndicate their debt positions (sell off their project exposures) to 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 from technical modelling. Calculations were made for three scenarios over three periods (2025-2027, 2028-2030, and 2031-2050), with high and low funding attraction alternatives for periods two and three[52]. Capex calculations

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[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.*

included grid costs, while Opex costs covered variable and fixed expenses, indicated in 2024 prices (refer to table below). While Opex was taken into consideration, the funding gap was focused on Capex.

Table 44: Capex Funding Gap per Scenario and (Private) Funding Attraction Alternatives[53] (R’ billions p.a., 2024 prices and % of GDP)

	Scenario A (Green industrialisation)		**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	99.1 (1.35%)		-17.4 (-0.24%)		13.9 (0.19%)	
2028 – 2030	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**	**Low (67%)**	**High (75%)**
Capex gap	140.0 (1.91%)	130.6 (1.78%)	23.6 (0.32%)	14.1 (0.19%)	54.9 (0.75%)	45.4 (0.62%)
2031 – 2050	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**	**Low (50%)**	**High (60%)**
Capex gap	107.3 (1.46%)	95.5 (1.30%)	88.5 (1.21%)	76.7 (1.05%)	122.1 (1.67%)	110.3 (1.51%)

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 are directly determined by the Capex requirements. Specifically, the timing of Capex outlay requirements for the underlying technology mix and the associated learning rates of these sets of technologies.

Even in the short term (2025-2027), Scenario A has a significant Capex gap of R 99 billion per annum, despite an estimated annual average funding availability of R 127 billion. Scenario B indicates adequate funding availability, and Scenario C (Business-as-usual) shows an annual gap of R 14 billion. The Capex funding gap increases from an annual average of around R 32 billion across the three scenarios during 2025 to 2027 to R 68 billion during 2028 to 2030, and finally to R 100 billion during 2031 to 2050.

Scenario B (Market Forces) shows the lowest overall Capex funding gap, with Scenario A (Green Industrialisation) and Scenario B (Market Forces) in line with one another. However, from 2025 to 2030, the annual average Capex outlay for Scenario A is much higher than for Scenario C, which could challenge the country’s ability to secure these levels of funding in the short-to medium term. The average annual Capex funding gap for Scenario A reduces in the third period (2031-2050) compared to Scenario C, but is still higher than Scenario B.

Effective tariff setting and collections are crucial to recovering operational and maintenance spending. If Eskom and NTCSA cannot collect sufficient tariff revenues to cover its operational and maintenance spending over and above the repayment of Capex over the predetermined period (i.e., the Weighted

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[53] *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.*

Average Cost of Capital), there is a distinct risk that the funding gap could grow wider. Including Opex, the gap increases to 2.21%-3.60% of GDP (2025-2027) and 2.93%-5.28% (2031-2050). From 2031 – 2050, Scenarios A's Opex is much lower than the Opex of the other two scenarios, which leads to this scenario having 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 funding gap over the long-term. 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, utilising alternative funding models, unlocking wider secondary market debt participation, developing a pipeline of bankable projects, and facilitating credit enhancement / support from 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 recognizing the need for substantial investment, the energy sector struggles with balancing cost-reflective tariffs and substantial tariff increases due to the absence of developed alternative funding and pricing mechanisms.

The Electricity Regulation Act aims to decentralize and modernize 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 such as 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 minimizing 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 Industrialisation) assumes optimistic technology learning rates, lower fuel prices, higher carbon tax, and a strong alignment with both local and global green industrialisation 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 R 1 651 billion for generation; lowest operation, maintenance and fuel investment of R 1 552 billion; highest grid capacity investment of R 383 billion; but the lowest total system investment of R 3 586 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 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 R 1 229 billion; R 2 166 billion for operations,

maintenance and fuel; and R 262 billion for grid expansion, with a total system investment of R 3 657 billion – 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 – 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 industrialisation. 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 R 1 446 billion for generation Capex investment; R 2 490 billion for operations, maintenance and fuel – highest; and R 231 billion for grid Capex – lowest; resulting in the highest total system investment of R 4 166 billion – 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 – 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.
  - Limited incentives for renewables and BESS, increasing overall vulnerability to fuel price fluctuations and carbon-related export market barriers.

New Generation Capacity: In all scenarios, the largest component of new generation capacity consists of variable renewable energy (VRE) technologies, such as solar PV and wind, supported by new battery energy storage systems (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. 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

Significant Funding Gap: The market sounding participants did not expect a funding gap in the short term, based on the premise that a R 100 billion per annum is required. However, from the finance requirements calculations indicating higher annual funding levels, the estimations from this study indicate that a Capex funding gap is likely for the period 2025 - 2027, particularly under Scenario A (Green Industrialisation). Under all scenarios, the funding gap increases significantly during the periods 2028 to 2030 and 2031 to 2050).

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 generation, transmission, and distribution infrastructure. Private sector funding, including donor contributions, will be necessary.

Energy Regulation and Market Reform: The market sounding participants (financiers) detailed that regulatory, market, and project (supply) challenges could lead to diminishing private sector funding in the medium and 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 in comparison with 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 increased energy infrastructure tax incentives are 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 REIPPPP to attract investment and enhance 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, is the best option for exports (in the context of regulations such as CBAM), meets the NDC targets and does so with the lowest total system investment[54]. Subject to assessment of the socio-economic impact of Scenario A (to be included in a supplementary report) and subject to the realisation of the local and global pathway assumptions (in particular, renewable energy technology learning rates) relevant to Scenario A, 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 achievement of Scenario A is conditional on the realisation of the local and global pathway assumptions relevant to this scenario, it is recommended that Government should, where possible, pursue policy decisions which enable this pathway and its associated assumptions.
- **Scenario B** is premised on a local and global environment which is less focussed on a green transition and as a result 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. Under 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 wider climate impacts resulting in Southern Africa warming at twice the global rate (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 focussed on a green transition, 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

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

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 well be created 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 Scenario A or B in response to wider climate impacts resulting in Southern Africa warming at twice the global rate (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 stabilisation 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 life**: Decommission coal plants with shorter remaining life instead of deploying AQ retrofits. Conduct thorough cost-benefit analysis before investing in AQ retrofits.
- **Investigate and monitor 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.
- **Decentralised energy systems**: Implement renewable energy-based microgrid systems for rural communities to improve quality of life and create job opportunities.
- **Co-locate RE generation infrastructure with demand**: Reduce transmission losses and improve energy efficiency by co-locating RE 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 subsidising 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 to increase investor confidence and leverage additional capital though 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 / products need to be repriced to ensure liquidity and long-term participation from the secondary market given local commercial bank sector exposure limits.
    - Improved clarity and consistency when implementing programmes (such as the coal fleet decommissioning schedule) to ensure a pipeline of bankable projects is developed over the long-term.
    - National Treasury backed guarantees or similar guarantee type vehicles such as a World Bank Guarantees Program with an 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.
    - From a market risk perspective, the development of a wholesale energy market should be finalised 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.
    - Reindustrialisation 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 applications for Eskom's Budget Quote process.
    - Promotion and education of pension funds relating to alternative assets 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.

Policy and regulatory enhancement

- **Renewable Energy Fund:** Introduce a renewable energy surcharge, similar to Germany's EEG, to fund clean energy projects. This will help 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. It must however be noted that there are still several tax incentives under the Income Tax Act (No. 58 of 1962) in South Africa that can be used for energy infrastructure development, such as section Section 12B – Capital Allowance for Renewable Energy Assets and Section 11(e) of the Act relates to the depreciation (wear and tear) of plant, machinery, and equipment used in the production of income.
- **Targeting Mechanisms:** Mandate municipalities to source a set percentage of electricity from renewables. Use Renewable Energy Certificates (RECs) to ensure compliance and incentivize investments.
- **Pricing and Returns:** Create capacity and ancillary services markets to secure 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:** Move the Grid Access Unit 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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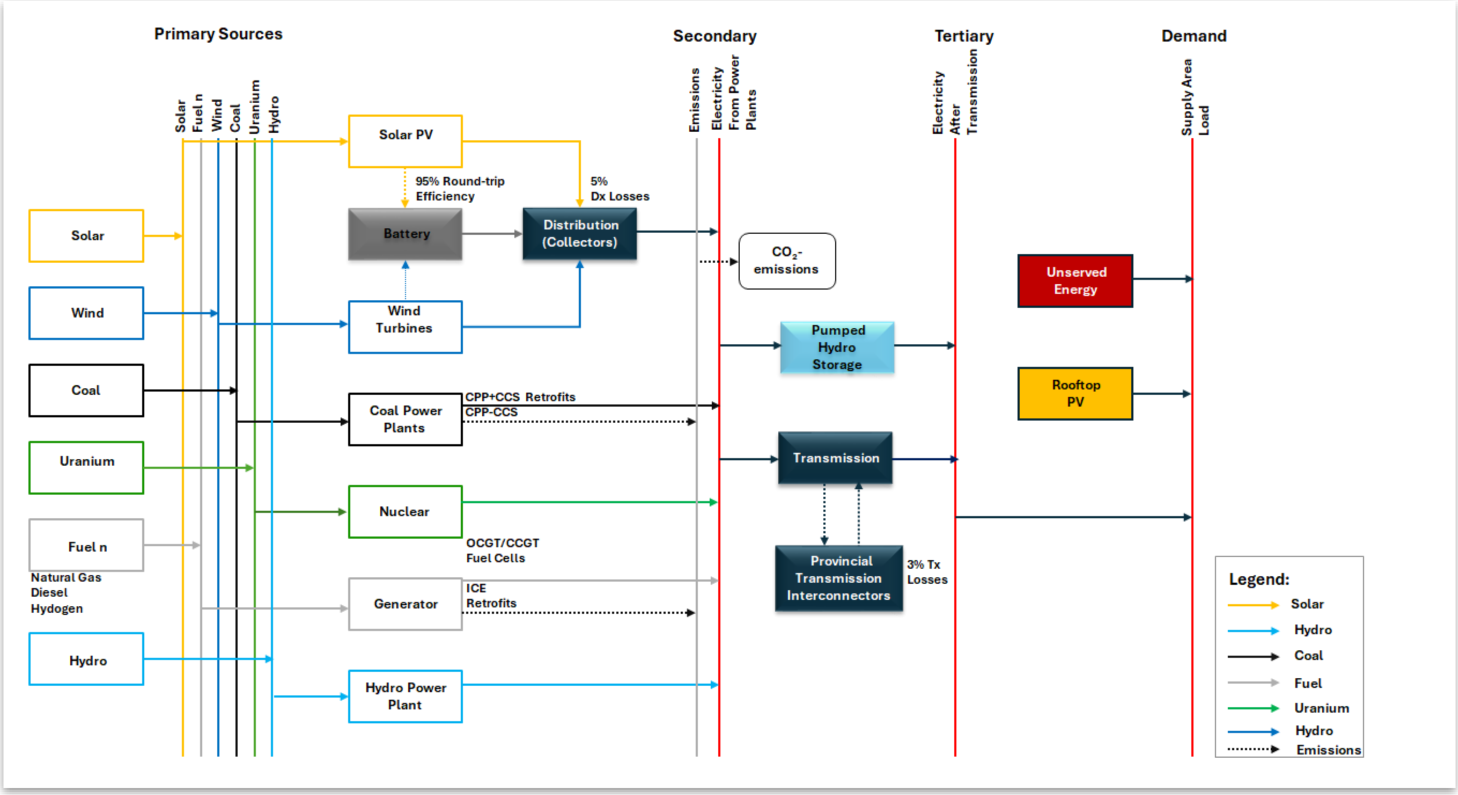
Annexures

Annexure A: Reference Energy System Diagram



Annexure B: Power System Analysis

The objective of the power system analysis is to quantify the transmission evacuation capacity that is used as inputs to the energy modelling. This task also was used to test the capability of the planned infrastructure to collect the proposed generation capacity at various supply areas and transmit this power to the load centre. This is to ensure that the proposed grid strengthening is practical and that the outcome of the grid costs is realistic. It should be noted that the NTCSA develops the detailed 10-year transmission development plan, and this task doesn't seek to replicate or replace the TDP. The main objective is to provide realism in the developed grid cost that is used to determine the electricity funding gap.

i. Power System Model Setup

The modelling for this task was done using PSSE software (the same software which NTCSA uses for its network modelling).

The power system analysis assessed the transmission network's capability to collect and evacuate 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 were conducted in PSSE 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.

It should be noted that the transient stability studies were not performed in this study.

ii. Inputs to Power System Modelling

The initially intended approach was to source the Eskom TDP PSSE casefile and use that as a base to develop the future network. However, in the absence of Eskom casefiles the publicly available information such as the TDP, GCCA and other sources were used to develop and update the South African Transmission network to align with the TDP2032. The Transmission network was then developed within the PSSE simulation tool to reflect the status of the South African grid.

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 done utilising 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 and representing typical inverter technology available in the market today.
- Where network component information is not readily available, typical values were assumed, or generic models utilised.
- Renewable energy and BESS facilities are represented as an equivalent PQ generation source, with applicable real and reactive power values that represent the MVA of the plant and the operating power factor limits, and
- Modelling was steady state only, not dynamic.

iv. Power System Model Outputs

- Analysis and results conducted / obtained over the study horizon / 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 / investments.
- Estimation of the Capex for the transmission and distribution investments up to 2050, and
- Geographical location of the transmission and generation build.

The table below shows the results of the corridor transfer limits and Figure 55 below that shows a geographical view of the transmission lines forming corridors. The transfer limits were simulated with N-1 contingency simulating the loss of critical equipment in the system, such as a loss / failure of 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	2455 MW (N - 1)	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 531MW 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 – Everest275 kV line
	2030	248 MW	589 MW	570 MW with a contingency of losing Snowdon – Everest 275 kV line

Corridor	Year	SIL (N–1)	Loadability (N–1)	PV transfer (N – 1)
	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 400kV line
	2030	4 204 MW	9 462 MW	5027 MW with a contingency of losing Matimba – Spitskop 400kV line
	2035	4 204 MW	9 462 MW	5027 MW with a contingency of losing Matimba – Spitskop 400kV 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
	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

Corridor	Year	SIL (N–1)	Loadability (N–1)	PV transfer (N – 1)
	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

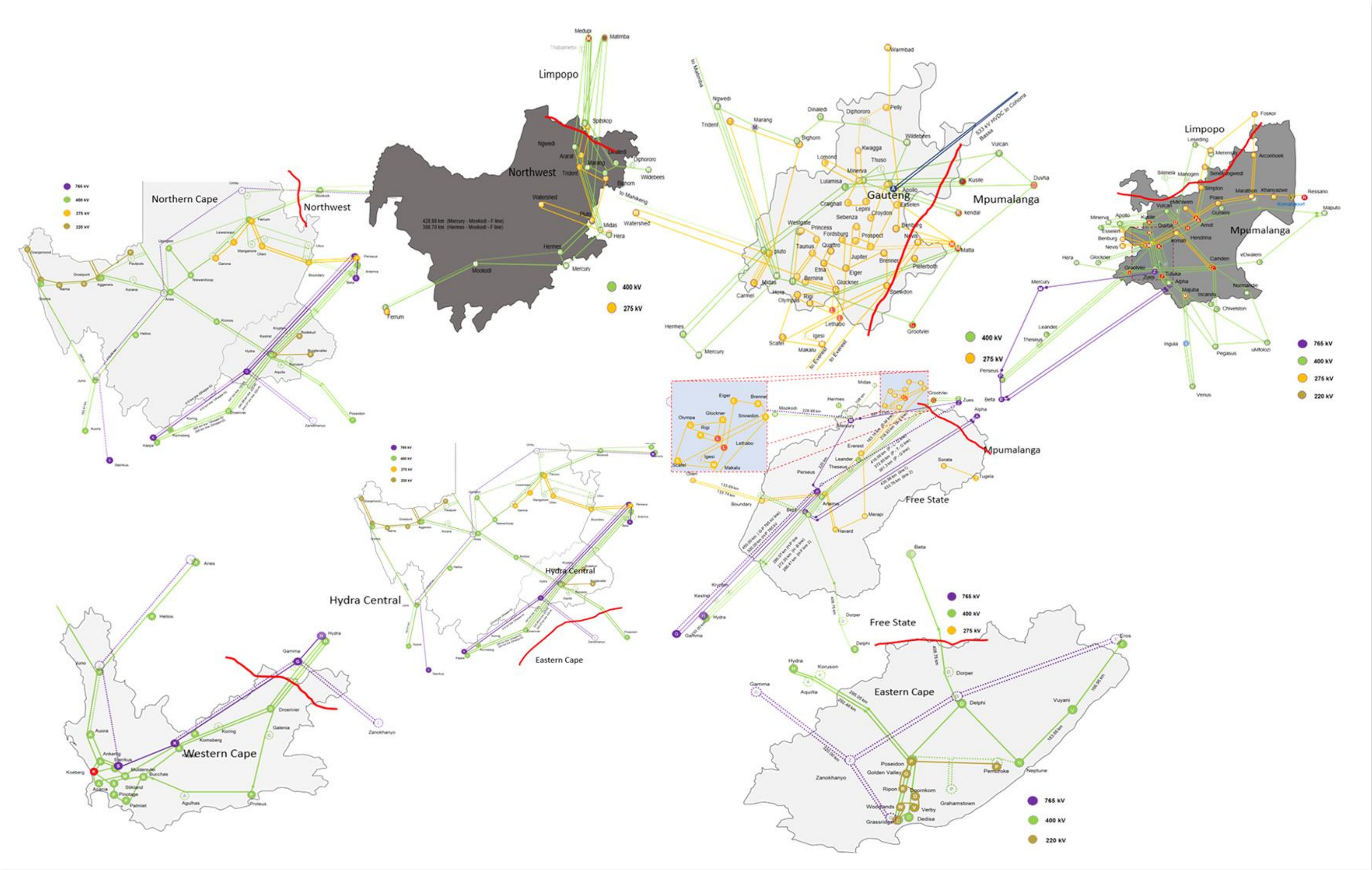


Figure 55: South Africa Transmission Corridors

Annexure C: Transmission Infrastructure Investments Breakdown

As described in the methodology section of this report, the transmission grid was modelled as the copper-plate post 2030, thus 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 scenario A, B, and C.

The table below shows the additional required transmission corridor capacity by year 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. This requires a combination of the 765 kV and 400 kV lines to unlock this capacity. It should be noted that this study did not consider the High Voltage Direct Current[55] (HVDC) technology due to limited knowledge of the costing assumptions. The NTCSA will likely include HVDC technology in its future transmission development plans (TDP) once this technology design and costing is well understood.

Table 46: Transmission Capacity Requirements

From	To	Scen A (MW)	Scen B (MW)	Scen C (MW)
Western Cape	Hydra Central	6964	6732	7265
Hydra Central	Eastern Cape	11114	6819	3034
Hydra Central	Northern Cape	2466	0	1693
Hydra Central	Free State	17592	15486	18835
Free State	Mpumalanga	5258	7186	0
Free State	Gauteng	20100	20100	19100
Northern Cape	North West	13125	11749	11677
North West	Gauteng	0	24807	24688
Mpumalanga	Gauteng	20000	12027	20000
Limpopo	North West	23700	29071	28490
Limpopo	Mpumalanga	4359	344	258
Western Cape	Northern Cape	5275	5275	5250
Eastern Cape	Free State	10022	8357	5596
Limpopo	Gauteng	22170	28635	30000
Northern Cape	Free State	15753	11722	5271

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[55] *HVDC is a technology is a method of transmitting electricity over long distances using direct current (DC) instead of alternating current (AC).*

The table below tabulates the transmission lines transfer limits assumptions. In summary, the 400 kV single circuit line is assumed to have the transfer limit of 1,000 MW when compensated and the 765 kV single circuit line is assumed to have the transfer limit of 2,500 MW when compensated over long distances (>500km).

Table 47: Transmission Lines Transfer Assumptions

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

The table below shows the cost assumptions for the transmission stations, and the associated usable capacities / utilisation. It is assumed that the main transmission stations (MTS) collecting distributed renewable energy plants will have an average utilisation of 70%, where other MTS will be fully utilised @ 100% and others underutilised @ 50%. The assumption on the larger dispatchable plants such as the OCGT or CCGT is that the MTS will be sized for the power plant capacity and thus assumed 100% utilisation.

Furthermore, the MTS collecting distributed renewable energy plants have assumed the N-1 on the transformation capacity with a maximum of 4x 500 MVA, 400/132 kV.

Table 48: Transmission Station Cost Assumptions

Resource	MTS	Capacity (MW)	Utilisation (%)	Used Capacity (MW)
PV	400/132 kV, 4 x 500 MVA	1425	70%	997.5
Wind	400/132 kV, 4 x 500 MVA	1425	70%	997.5
Nuclear	400/33 kV, 5 x 500 MVA	1900	100%	1900
Gas	400/33 kV, 5 x 500MVA	1900	100%	1900
PHS	400/33 kV, 5 x 500 MVA	1900	100%	1900

The table below tabulates the sub-transmission collector network cost assumption. It is assumed that PV and Wind power plants connects to the transmission station with the average sub-transmission line length of 30km and BESS with an average line length of 20km. 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: Sub-Transmission Collector Network Cost Assumptions

				Dedicated	shared		
Technology	**MEC (MW)**	**distance (km)**	**132 kV TwinTern**	**Metering Station**	**Collector Station**	**Cost (R'm)**	**R'm/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 scenario A, B and C are indicated in the table below.

Table 50: Grid Cost Summary (R'm)

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 Re-furbishment)	**R 921 748**	**R 630 214**	**R 555 244**

Annexure D: Energy Modelling Sensitivity Analysis

i. Sensitivity 1 – No growth to 2040

Question: What is the capital cost required just to replace the decommissioned coal fleet by 2040 with no increase in demand?

The undiscounted, cumulative capital cost required for new generation is R 1 262 billion by 2030, R 1 801 billion by 2035, R 2 670 billion by 2040, i.e., R 178 billion per annum, on average.

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 56: Sensitivity 1 - No Growth to 2040

ii. Sensitivity 2 – Medium TDP Demand

Question: What happens if one reduces the demand growth rate from IRP 2023 Ref Case (CAGR: 2.1%) to Medium TDP Demand (CAGR: 1.9%)?

The Medium TDP Demand scenario is approximately 5% less than the IRP 2023 Ref Case. As a result, the model builds approximately 5% less new 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 57: 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 1GW 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 58: 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 generation investment away from new gas and toward new renewables and storage. Total generation costs increase by approximately 4% over the period to 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
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 59: 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 reduce 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 60: Sensitivity 5 - 30% Non-VRE Premium

vi. Sensitivity 6 – Low EAF

Question: What happens if the EAF of Eskom coal fleet (except for Medupi and Kusile) remains at 60% and never improves?

If Eskom's coal fleet maintains a 60% EAF, the system compensates 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 61: Sensitivity 6 - Low EAF

vii. Sensitivity 7 – Delayed Coal Decommissioning

Question: What happens if one forces the Eskom coal fleet decommissioning dates to be 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.


Total Annual Capacity - Scenario B (GW) (Reference)

Total Annual Capacity - Sensitivity 7 (GW) (Delayed Coal)

Cost Summary (R'bn)

Generation - Scenario B (TWh) (Reference)

Generation - Sensitivity 7 (TWh) (Delayed Coal)

Aggregated CO2 Emissions (Mt)

New Capacity (GW)

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 62: Sensitivity 7 - Delayed Coal

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 reduce since cost of AQ retrofits not incurred. VRE and BESS contribute more of the energy mix from 2035 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 63: Sensitivity 8 - No 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 storage. Coal dispatches less between 2025 and 2035 to keep CO_2 emissions within the 3.0 Gt budget constraint. Total generation costs increase.

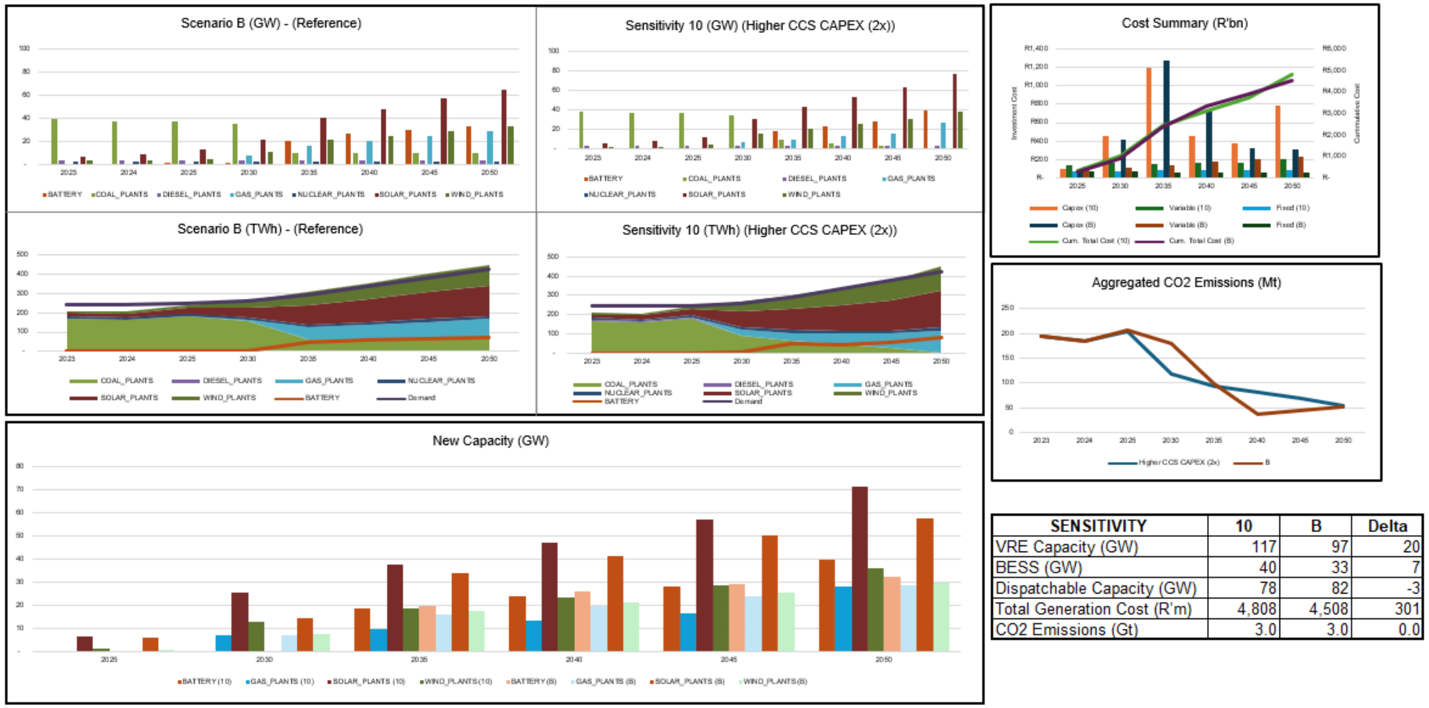
SENSITIVITY	9	B	Delta
VRE Capacity (GW)	80	97	-16
BESS (GW)	31	33	-2
Dispatchable Capacity (GW)	84	82	2
Total Generation Cost (R'bn)	4,695	4,508	187
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 64: Sensitivity 9 - Pessimistic Learning Rate

x. Sensitivity 10 – Higher CCS CAPEX

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 1.5x and 2x the base cost. At twice the base cost, CCS is no longer deployed with renewables and gas fully replacing the phased-out coal capacity by 2050. New renewables are built sooner to compensate for the additional CO_2 emissions from coal plants in later years, to keep 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 65: 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 is similar to Scenario B.

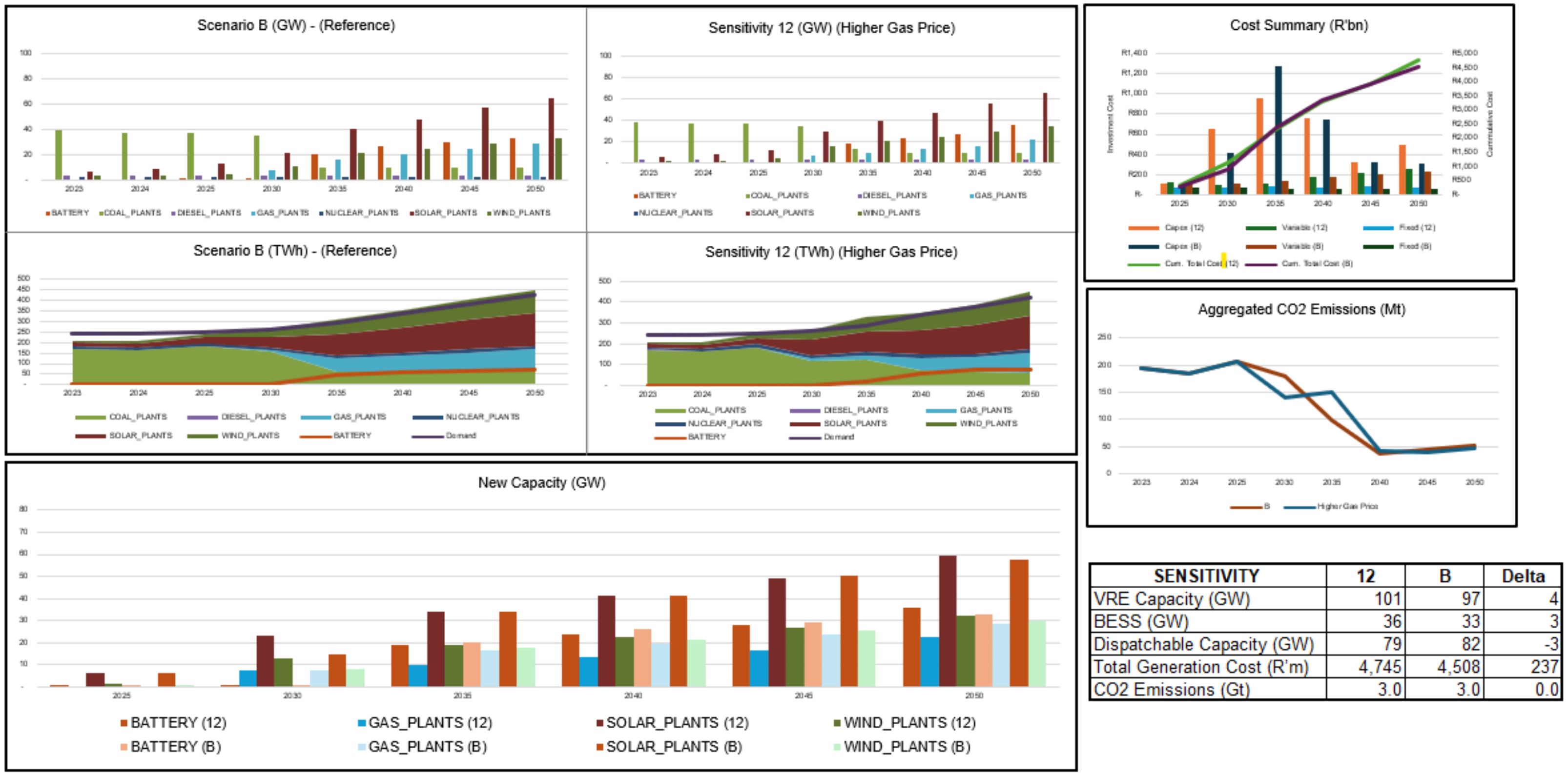
SENSITIVITY	11	B	Delta
VRE Capacity (GW)	98	97	1
BESS (GW)	33	33	0
Dispatchable Capacity (GW)	79	82	-3
Total Generation Cost (R’m)	4,541	4,508	33
CO2 Emissions (Gt)	2.9	3.0	-0.1

Figure 66: 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 storage, and raises overall system costs.



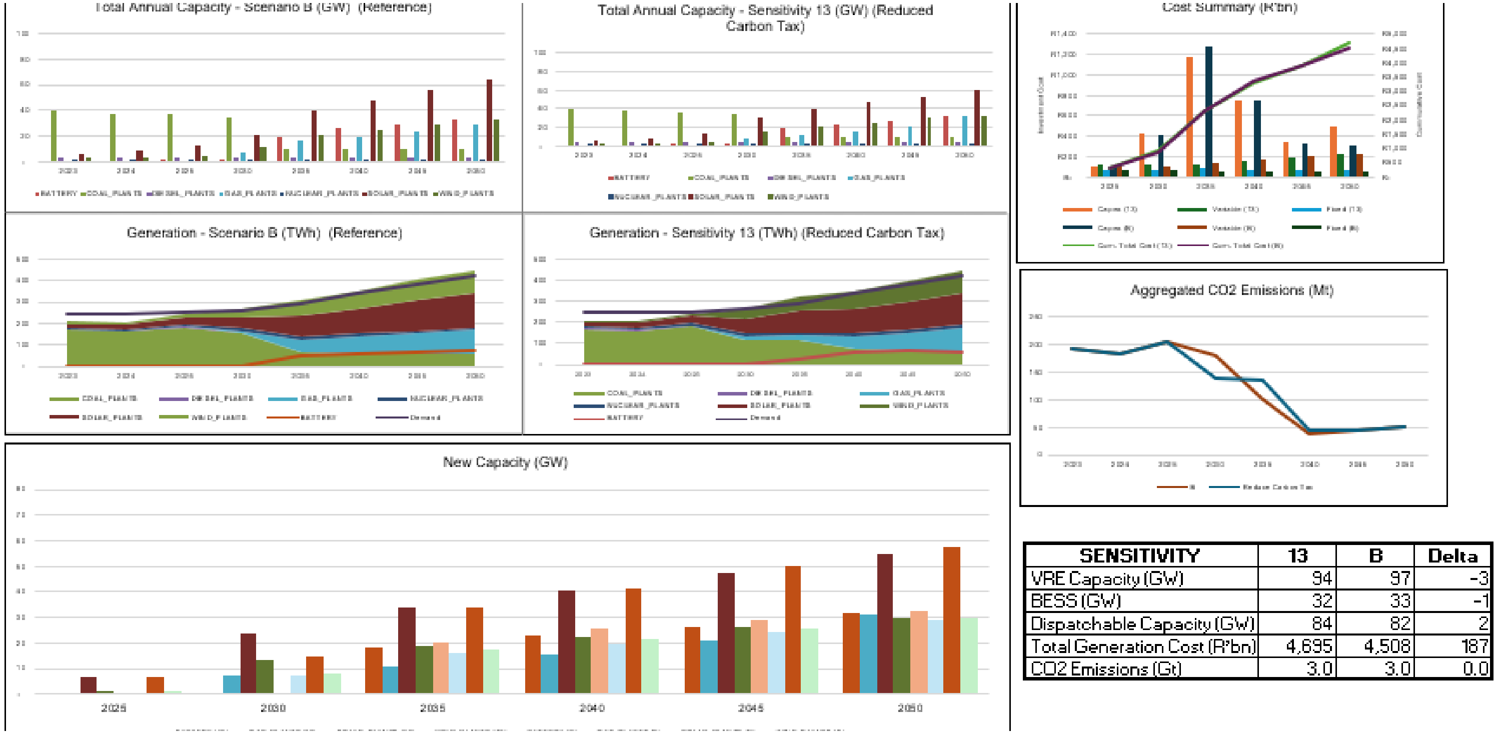
SENSITIVITY	12	B	Delta
VRE Capacity (GW)	101	97	4
BESS (GW)	36	33	3
Dispatchable Capacity (GW)	79	82	-3
Total Generation Cost (R'm)	4,745	4,508	237
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 67: Sensitivity 12 - Higher Gas Price

xiii. Sensitivity 13 – Reduced Carbon Tax

Question: What happens if the Carbon Tax is increased? From USD104/tonne CO_2 to USD68/tonne 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 receive AQ retrofits and remain online until 2045, without CCS retrofits. Total generation cost increases due to more coal consumption, however when including the cost of carbon tax, Sensitivity 13 has a lower cost than Scenario B.



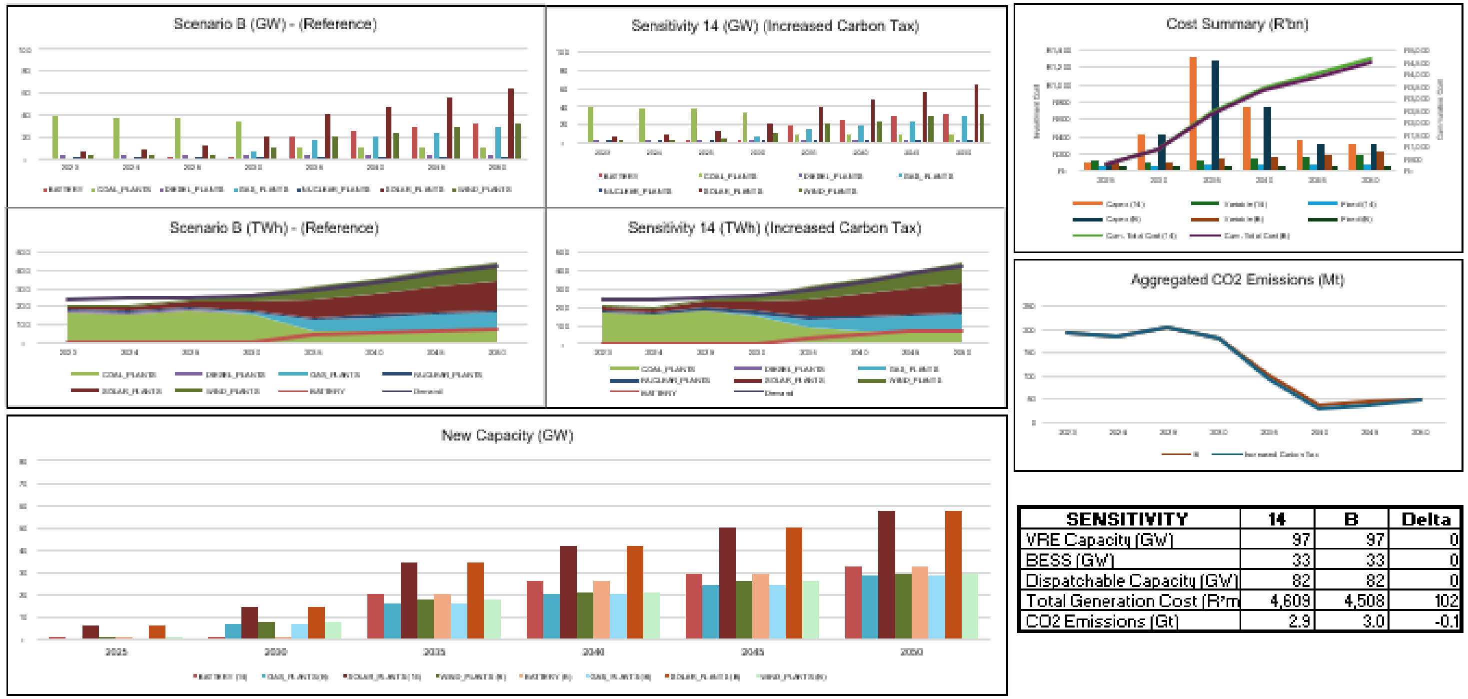
SENSITIVITY	13	B	Delta
VRE Capacity (GW)	94	97	-3
BESS (GW)	32	33	-1
Dispatchable Capacity (GW)	84	82	2
Total Generation Cost (R'bn)	4,695	4,508	187
CO2 Emissions (Gt)	3.0	3.0	0.0

Figure 68: Sensitivity 13 - Reduced Carbon Tax

xiv. Sensitivity 14 – Increased Carbon Tax

Question: What happens if the Carbon Tax is increased? From USD104/tonne CO_2 to USD188/tonne CO_2 in 2050

Higher carbon tax (which increases more substantially 2035 to 2050) reduces gas generation in favour of renewables between 2035 and 2050, but 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 (i.e., 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 69: Sensitivity 14 - Increased Carbon Tax

Annexure E: Emerging, Innovative, and Disruptive Gx and Tx Technologies

A disruptive technology is a specific technology that can fundamentally change not only established technologies but also the rules and business models of a given market, and often business and society overall (Perez and Leach, 2022). Below, the list refers to many technologies and associated functions in the electricity industry value chain that could be categorised as being disruptive or innovative.

- **Digitalisation in the energy sector:** The incorporation of digitalisation in renewables, combining data, analytics, and connectivity, serves as a facilitator in upcoming energy systems. New technologies should practically enable faster integration of renewable energy projects into the grid. Furthermore, 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 enhance the efficiency and reliability of energy systems, supporting the expansion of VRE technologies such as solar PV and wind. 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 helps in promoting 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 (Greentech Media, 2020).
  - Grid-Scale Energy Storage: Large-scale energy storage systems, such as lithium-ion batteries and pumped hydro storage, are crucial for balancing supply and demand. They help stabilize the grid by storing excess energy during low demand periods and releasing it during peak demand (StartUs-Insights, 2024).
  - High-Voltage Direct Current (HVDC) Transmission: HVDC technology allows for the efficient transmission of electricity 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 allows for the optimization of existing infrastructure, increasing the capacity and reliability of the grid (Arusi, 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 helps in balancing the load on

  the grid and reducing the need for additional power generation during peak periods (IEA, 2023).
  - Enhanced billing accuracy: With smart meters, billing is based on actual consumption rather than estimates, leading to more accurate and fair billing. This reduces disputes between consumers and suppliers and improves customer satisfaction (European Commission, 2024).
  - Fault detection and maintenance: Smart meters can quickly detect outages and other issues in the energy supply, allowing for faster response and maintenance. This improves the reliability and resilience of the energy grid (IEA, 2023).
  - Customer empowerment: Consumers have easy access to their energy consumption data and can give permission for third parties to use this data to provide tailored energy-saving solutions. This empowers consumers to take control of their energy usage and participate actively in the energy market (European Commission, 2023).
  - Personalised services: Energy suppliers can use data analytics to offer personalised energy plans and recommendations based on individual consumption patterns. This can include suggestions for energy-saving measures or the best times to use energy-intensive appliances (IEA, 2023).
  - Enhanced communication: Digital platforms facilitate better 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 optimise 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 better integrate variable renewable energy 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 helps in minimising

curtailment losses, optimising energy storage use, and ensuring a stable and reliable energy supply (Climavision, 2025). Specifically in South Africa's case, grid curtailment can be used to increase the integration of wind generation capacity within limited / constrained grid areas. This mechanism increases the utilisation of the transmission grid (capacity factor), thereby enabling more energy to flow through the limited grid capacity to the load. The weather forecasting will allow improved planning, prediction and associated dispatch of the flexible / dispatchable technologies, thus facilitating higher integration of VRE into South Africa's grid at any time.

While some technologies may be emerging in new regions, they can possibly be defined as disruptive. Fundamentally, emerging technologies are innovations still in development or in early adoption stages, such as advanced nuclear reactors and AI-driven energy management systems. They promise significant improvements but require further refinement and scaling. Contrastingly, disruptive technologies fundamentally alter existing markets and practices. Examples of disruptive technologies include solar photovoltaics and battery storage, which have drastically reduced reliance on fossil fuels. These technologies often face initial resistance but eventually reshape industries (Capgemini, 2025).

The following table provides a summary of the maturity levels and applicability to the South African context of innovative RE generation technologies towards 2050.

Table 51: Innovative RE Generation Technologies Towards 2050

Technology	Disruption Potential	Maturity	Expected Full Deployment	Applicability to South Africa
Small Modular Reactors (SMR)	Moderate	Developing	2040-2050	High, with various spheres of Government already 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, 2024).
Ocean Energy (Tidal and Wave)	Low	Preliminary stages	2040-2050	Low, due to limited coastal infrastructure and higher costs (IRENA, 2020).
Solar Photovoltaic (PV)	Very High	Fully developed	Ongoing	Very high due to abundant sunlight and decreasing costs (IEA, 2023; McKinsey, 2024).

Technology	Disruption Potential	Maturity	Expected Full Deployment	Applicability to South Africa
Floating photovoltaics (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, 2024a; 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).

Sources: Listed in table, PwC research

Annexure F: Mapping of Research Questions to Answers in the Report

Table 52: Research Questions Mapped to Report Sections

	Question	4.1 Energy Modelling	4.2 Sensitivity Analyses	5 Market Sounding	6 Funding Gap	7 Policy and Regulatory Review
1	Given the probable impacts of climate change on the global commitment to decarbonisation over the coming decades, what should the financing targets be for optimising achievement of 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 enable an increased level of investment in climate resilient energy infrastructure and services to achieve the NDP and SDG targets?			x		x
5	What are the barriers for achieving SDG 7.1 (universal access to affordable, reliable, sustainable, and modern energy services) and associated NDP goals, and what needs to be done?	x	x			x
6	How can reliability of power supply, which disproportionately affects poorer households, be improved to meet SDG targets and NDP objectives, whilst 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			