Eskom
National Transmission
Company South Africa ™

Medium-Term System Adequacy Outlook 2026-2030

Generation System Adequacy for the Republic of South Africa

30 October 2025

PURPOSE

The System Operator publishes the Medium-Term System Adequacy Outlook (MTSAO) under clause 2.1.2 (7) of the South African Grid Code, System Operation Code Version 10.1 of January 2022 which requires the System Operator (SO) to publish it on or before 30 October each year. The study is a review of the adequacy of available, committed and anticipated electricity generation resources to meet the South Africa's forecasted electricity demand in the upcoming five years. This publication aims to provide electricity consumers and all relevant stakeholders with an update on the state of the power system and to anticipate potential scenarios based on available data, forecasts and assumptions. The study is not intended to be used as either a generation resource plan or an operation plan, but rather serves as an indicator of the adequacy of the generation system under a range of different future scenarios and sensitivities.

DISCLAIMER

While the System Operator has taken reasonable care in the collection and analysis of data, forecasts and assumptions, the System Operator is not responsible for any loss that may be attributed to the use of this information from unforeseen circumstances that may arise from the continually changing South African energy industry. Before making any business decisions, interested parties are advised to seek separate and independent opinions in relation to the matters covered by this report and should not rely solely on data and information contained herein. Information in this document does not amount to a recommendation in respect of any possible investment. This publication is based on information available to the System Operator as of September 2025, unless otherwise indicated.

The MTSAO does not make recommendations regarding specific technology types or capacity sizes required to bridge the energy gap where it exists, as this responsibility lies within the jurisdiction of the Integrated Resource Plan (IRP) process. While the study for this year has assessed the capability of the transmission grid a multi-nodal approach, it does not extend to proposing and evaluating additional strengthening options required by the transmission network to fully accommodate all the generation and demand, as this responsibility falls under the scope of the Transmission Development Plan (TDP), which should be consulted for detailed information and project implementation timelines.

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ABBREVIATIONS

Term/Abbreviation	Definition
AGR	Annual Growth Rate
BESS	Battery Energy Storage System
BWs	Bid Windows
BQ	Budget Quote
CCGT	Combined-Cycle Gas Turbines
CSP	Concentrated Solar Power
DER	Distributed Energy Resources
DFFE	Department of Forestry, Fisheries and Environment
DEE	Department of Electricity and Energy
EAF	Energy Availability Factor
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt-hour
HCB	Hydro Cahora Bassa
IPP	Independent Power Producer
IRP	Integrated Resource Plan
MES	Minimum Emission Standards
MTS	Main Transmission Station
MTSAO	Medium-Term System Adequacy Outlook
MW	Megawatt
NERSA	National Energy Regulator of South Africa
NNR	National Nuclear Regulator
OCGT	Open-Cycle Gas Turbine
PV	Photovoltaic
RE	Renewable Energy
REIPPP	Renewable Energy Independent Power Procurement Programme
RFP	Request for proposal
RMIPPPP	Risk Mitigation Independent Power Producer Procurement Programme
SAGC	South African Grid Code
SO	System Operator
SSEG	Small-Scale Embedded Generation
TDP	Transmission Development Plan
TWh	Terawatt-hour

1. EXECUTIVE SUMMARY

The Medium-Term System Adequacy Outlook (MTSAO) is carried out in compliance to the South African Grid Code (SAGC: System Operator Code version 10.1 of January 2022). The grid code mandates the System Operator to publish, on or before 30 October each year, a review (called the "Medium Term System Adequacy Outlook") of the adequacy of the interconnected power system to meet the five-year future requirements of electricity consumers.

The current MTSAO, covering the period 2026 to 2030 calendar years and hereinafter referred to as the MTSAO 2025, assesses the capability of the South African power system to maintain a reliable electricity supply amid the growing demand, shutdown of baseload capacity and the increasing integration of renewables capacity.

The MTSAO key study inputs:

i. Demand assumptions

The study considered, as the input, the various growth scenarios in the energy demand with moderate demand scenario adopted for all base cases. The moderate growth scenario has a GDP growth rate of 2.7% and forecasts an average annual growth rate of 1.4% over the study period. Sensitivities were done on the low and high demand growth to assess their implications on the system. The low demand scenario assumes a GDP growth rate of 1.7% and forecasts an average annual growth rate of 0.6%, while the high demand scenario assumes a GDP growth rate of 3.5% and forecasts an average annual growth rate of 2.3% over the study period.

ii. Plant performance

The study used the moderate EAF projection of an average 60% over the study period as it reflects a moderate optimistic view, and sensitivities were done on the low (55%) and high EAF (67%) scenarios to assess their potential implications on the system.

iii. Capacity shutdown

The planned shutdown of 8.4 GW coal generation and the assumed end of the 1.15 GW Cahora Bassa supply contract by March 2030 represents the loss of about 9.5 GW of firm capacity, which is the first significant baseload cliff in the South African power system.

iv. New capacity assumptions and scenarios

Given the inherent uncertainty surrounding some of the new generation initiatives considered for the MTSAO 2025, the new capacity was grouped into four categories to represent various potential outcomes for future capacity development. These categories reflect the different levels of project readiness and likelihood of success and are as follows:

- Committed capacity consist of projects that have reached financial close and are either in construction or in the process of finalising their designs to enter the execution stage. It also includes the 6 GW CCGT capacity due to its strategic importance within the national energy framework. Committed capacity reflects a growth from 4.6 GW in 2026 to 14.8 GW by 2030.
- All new generation capacity includes all the projects from various stages of development that are in the pipeline within the five-year study period, and its capacity increases from 6.4 GW in 2026 to 29.7 GW in 2030.
- Risk adjusted generation capacity narrows the focus to those projects with a stronger probability of achieving commercial operation, despite their current phase in the development pipeline. This category assumes a delay in the 6 GW gas to post 2030. The capacity under this category increases from 4.6 GW in 2025 to 13.2 GW in 2030.
- Accelerated build new generation capacity reflects the increased capacity and accelerated timelines from the private initiative projects. This additional capacity from the business initiatives results in the total capacity considered in the MTSAO increasing from 10.6 GW in 2026 to 34.4 GW by 2030.

Four scenarios, namely the base case, all new capacity, the risk-adjusted new capacity, and the accelerated build were developed based on the above assumptions.

The 2026-2030 System Outlook

- The MTSAO 2025 used a moderately optimistic EAF with an average of 60%, and the system remains adequate at this level of EAF. The sensitivity done on the low EAF emphasises the importance of maintaining good plant performance as the drop in EAF will take the country back to the constrained system and possible load shedding.
- The period from 2029 to March 2030 will see a significant Eskom plant shutdown and the end of the supply contract from Cahora Bassa, reducing baseload capacity by 9.5 GW. This is a significant reduction in the system's baseload capacity, which will require measures to mitigate potential inadequacy.
- The study assumed 6 GW gas capacity to become commercial in 2030. This capacity is however at risk of being delayed post 2030. The scenario and sensitivity done on delaying the gas indicate that this will result in unserved energy of more than 4 TWh and OCGT usage of about 45% in 2030.
- The increasing penetration of solar PV, both utility scale and small scale embedded solar, which results in increasing excess energy levels. This is even more pronounced in the accelerated build scenario where the penetration of renewable energy technologies is even higher, and this capacity is commissioned earlier other scenarios. This scenario results in excess energy of more than 5 TWh in 2028.

- The integration of increasing solar PV systems necessitates that coal stations produce at minimum generation levels during the day and ramp up during the evening peak. The daily cycling pattern (up to 7 GW ramping) places operational stress on coal plants designed for baseload operation, which will in turn have a negative impact on plant performance.
- The coincidence of the unserved energy and excess energy occurring in the same day is observed. The unserved occurs during morning and evening peak demand periods, whereas excess energy is primarily observed during daytime hours, coinciding with peak solar PV generation.

2. INTRODUCTION

The Medium-Term System Adequacy Outlook (MTSAO) evaluates the power system's ability to meet electricity demand within predefined adequacy thresholds over the next five calendar years, as required by the South African Grid Code (SAGC: System Operator Code, January 2022). The current assessment, which is referred to as MTSAO 2025, covers the calendar years 2026 to 2030. The assessment is limited to the identification of possible electricity supply surpluses or shortfalls and its outcomes have the following key implications:

- It serves as a foundational reference point for policy makers in the decision making of procurement of power generation resources. Specifically, it provides insight into whether the current generation capacity is sufficient to meet demand or if additional resources need to be acquired.
- It informs the general public about possible generation shortfalls or surpluses and associated risks. This includes providing stakeholders with insights into the extent and timing of supply risks, such as the amount of unserved energy or excess energy.

The study does not make recommendations regarding specific technology types or capacity sizes required to bridge the energy gap where it exists, as this responsibility lies within the jurisdiction of the Integrated Resource Plan (IRP). It also does not propose and evaluate any transmission grid strengthening options required to fully accommodate all the generation and demand, as this responsibility falls under the scope of the Transmission Development Plan (TDP).

3. METHODOLOGY

The MTSAO 2025 adopts a different approach compared to the previous MTSAO studies. Previous studies were based on single-node modelling, focusing solely on the generation adequacy without considering the transmission grid. This year's study introduces a multi-nodal approach, which evaluates not only the adequacy of the generation system but also the capability of the existing and planned transmission network within the study horizon to evacuate power to various regions across the country. The inclusion of transmission grid as part of the adequacy analysis necessitated the disaggregation of energy demand forecast to Main Transmission Station (MTS) levels, and mapping of various generators to their corresponding nodes within the transmission network to reflect the real-world grid topology.

This modelling approach enables the reporting of potential surpluses and shortfalls at both national and regional levels. National reporting offers a holistic view of the overall power system adequacy, providing a unified metric for benchmarking system's performance over time. At the same time, the regional level reporting provides a detailed understanding of the spatial distribution of energy adequacy issues, allowing for identification of specific regions where unserved energy or excess energy is most evident. This level of detail helps identify regions of concern and assist with determining whether energy adequacy issues are caused by under-or-over generation or transmission grid constraints.

Furthermore, the study employs the Monte Carlo simulation method to account for the inherent randomness of certain parameters used to assess system adequacy, given their intermittent and unpredictable nature. These parameters include demand forecast, wind generation, solar generation and unplanned power plant outages. The Monte Carlo simulation method is a mathematical technique that leverages historical data to forecast potential future outcomes of uncertain events. The outcomes of this technique provide a range of probable results based on random samples, and the results of the MTSAO represent an average across all the samples. The number of samples defined is based on a balanced trade-off between simulation runtime, input-output convergence and quality of results. The results of these Monte Carlo simulations are then reported annually to determine the extent to which the system meets or violates the adequacy metrics when dispatching available generators optimally.

The MTSAO process, which shows how the input data consisting of demand and supply inputs is assessed hourly to quantify potential generation surpluses or shortfalls over the next five calendar years, is illustrated in Figure 1.

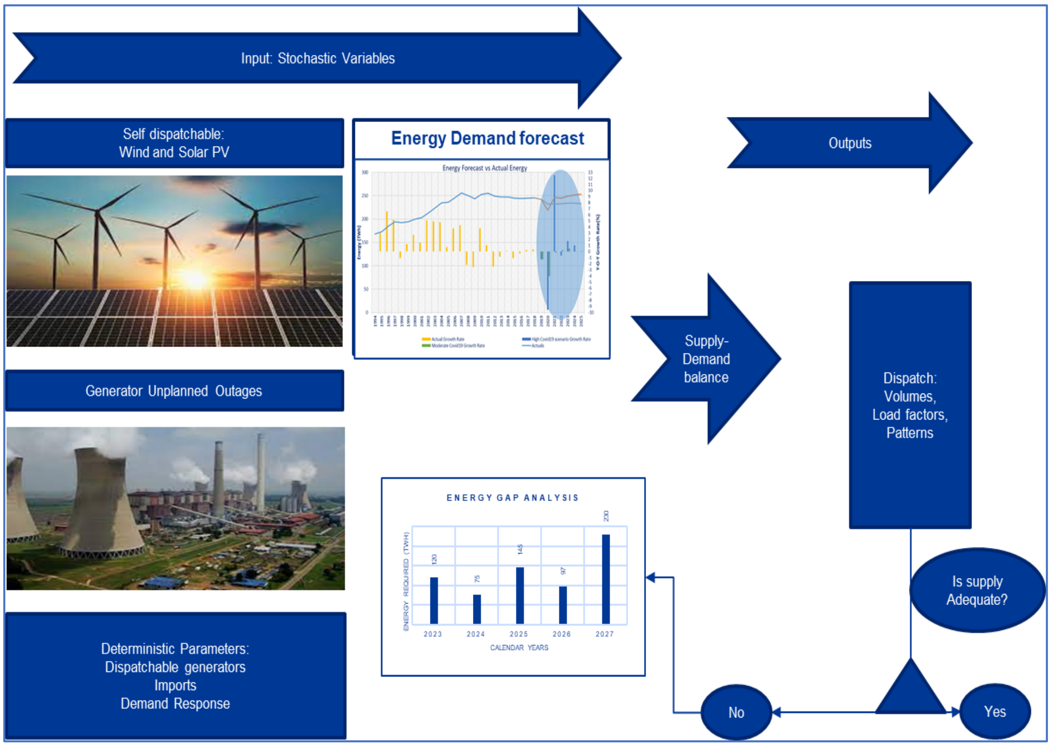

Figure 1: MTSAO methodology.

The electric power system is deemed to be adequate if it meets the following adequacy metrics:

i. The total amount of unserved energy per year is less than 20 GWh.

ii. The capacity factor of open-cycle gas turbines is less than 6% per year.

4. STUDY INPUTS

In doing the MTSAO study, the grid code requires the System Operator (SO) to consider the following:

- Possible scenarios for growth in the electricity demand, which includes both the South Africa's demand and exports to neighbouring countries.
- Possible scenarios for increases or decreases in available generation to meet the expected demand, inclusive of all licensed generators by the National Energy Regulator of South Africa (NERSA), imports from neighbouring countries, demand side management resources and Distributed Energy Resources (DERs).
- Possible scenarios for new generation projects, inclusive of sensitivity analysis on their likelihood of success.
- Any additional information that SO may reasonably consider relevant.

The study therefore considered several key assumptions which are detailed in the following sections. Due to the level of uncertainty surrounding both the demand-side and supply-side assumptions, a cone of uncertainty has been provided, where possible, to assess a range of future realisations.

4.1 Energy Demand Forecast

The MTSAO study considered three demand scenarios namely the low, moderate, and high demand. All the scenarios incorporate Gross Domestic Product (GDP) as a key input in econometric regression models to project South Africa's electricity demand, aligning with the country's anticipated economic growth. The correlation between GDP and electricity demand helps capture how different levels of economic performance impact demand growth, and this relationship serves as a key reference point for policy makers in determining the demand requirements needed to achieve the desired economic growth targets.

The low demand scenario reflects weaker economic performance across all sectors, while the moderate demand scenario reflects a moderate economic growth for all economic sectors in the medium term. The high demand scenario, on the other hand, assumes favourable economic conditions in high electricity intensive sectors, namely industrial sector (i.e. Steel and ferroalloy production) and successful rollout of key policy reforms to stimulate economic expansion. These scenarios are illustrated graphically in Figure 2.

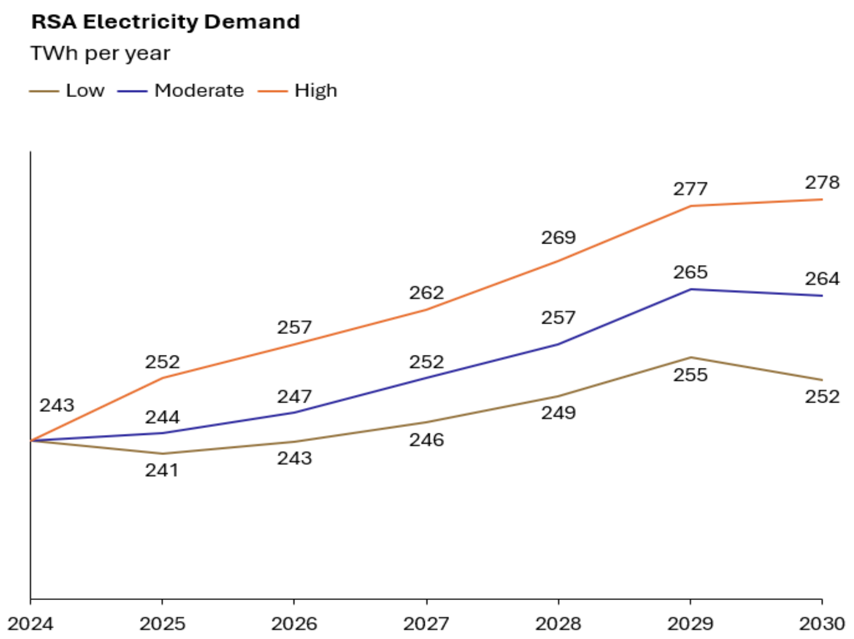

Figure 2: Energy demand forecast.

The low demand scenario assumes a GDP growth rate of 1.7% and forecasts an average annual energy demand of 0.6% over the 5-year study period. Under this scenario, demand is expected to rise from 243 TWh in 2024 to 252 TWh by 2030. The moderate demand scenario assumes a GDP growth rate of 2.7% and forecasts an average annual energy demand increase of 1.4% over the 5-year study period. The demand in this scenario is expected to rise from 243 TWh in 2024 to 264 TWh by 2030. Lastly, the high demand scenario assumes a GDP growth rate of 3.5% and projects a higher average annual energy demand growth of 2.3%, with energy demand rising from 243 TWh in 2024 to 278 TWh by 2030. The study has adopted the moderate demand projection for the study scenarios, as it reflects a moderate optimistic view and has conducted sensitivity analysis on the low and high demand scenarios to assess their potential implications on the system.

The notable decline in 2030 is attributed to the ending of the Mozal smelter contract, which the forecast assumes to be extended beyond its official expiry date of December 2025 to March 2030. If the agreement is not extended as assumed, demand projections will change, and this will impact the adequacy assessment results presented in this report.

4.2 Reserves Requirements

The MTSAO not only assesses the ability of a generation system to supply power to customers, but also includes the ancillary services requirements which are critical in maintaining system stability.

The study relied on the 2025 Ancillary Services Technical Requirements report, published by the SO to model the various types of reserves and the minimum provisions required from contributing generators or demand-side loads in the system. These reserves are briefly described below, and their respective minimum provisions are outlined in Table 1.

i. Instantaneous reserves: generating capacity or demand-side managed load that must be fully available within 10 seconds to arrest a frequency excursion outside the frequency dead band. This reserve response must be sustained for at least 10 minutes.

ii. Regulating reserves: generating capacity or demand-side managed load that is available to respond within 10 seconds and is fully activated within 10 minutes. The purpose of this reserve is to make enough capacity available to maintain the frequency close to the scheduled frequency and keep tie-line flows between control areas within schedule.

iii. Ten-minute reserves: generating capacity or demand-side managed load that can respond within 10 minutes when called on. It may consist of a quick offline start generating plant (for example, hydro or pumped storage) or demand-side load that can be dispatched within 10 minutes. The purpose of this reserve is to restore instantaneous and regulating reserves to the required levels after an incident.

iv. Emergency reserves: includes interruptible loads, generator emergency capacity, and gas turbine capacity. These requirements arise from the need to take quick action when any abnormality arises in the system.

v. Supplemental reserves: generating or demand-side load that can respond in 6 hours or less to restore operating reserves.

Table 1: Reserve requirements for seasonal peak and off-peak in MW

Reserves	Season		2025/26	2026/27	2027/28	2028/29	2029/30
Instantaneous	Summer/Winter	Peak	650	650	650	650	650
		Off-peak	850	850	850	850	850
Regulating	Summer/Winter	Peak/Off-peak	750	780	810	840	870
Ten-minute	Summer/Winter	Peak	800	770	740	710	680
		Off-peak	600	570	540	510	480
Operating	Summer/Winter	Peak/ Off-peak	2200	2200	2200	2200	2200
Emergency			1200	1200	1200	1200	1200
Supplemental			400	400	400	400	400
Total			**3800**	**3800**	**3800**	**3800**	**3800**

4.3 Existing Generation Fleet

4.3.1 Total RSA Installed generation capacity

South Africa's installed generation capacity is currently at around 65 GW and a breakdown of this capacity by technology is shown in Figure 3 below.

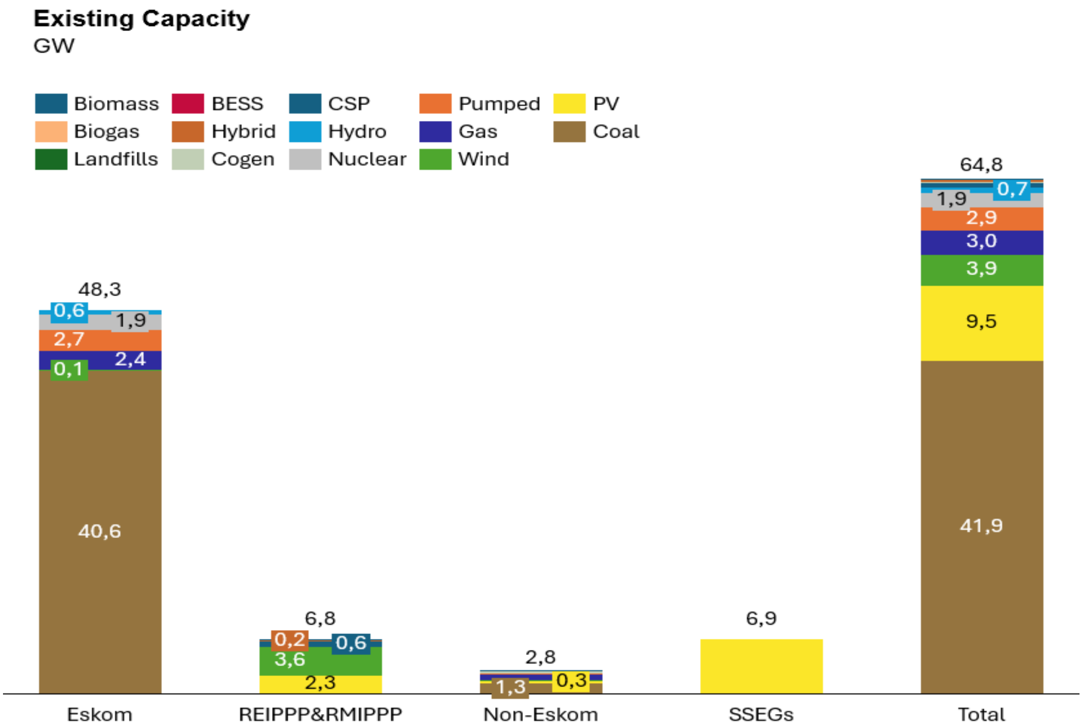

Figure 3: South Africa's installed generation capacity.

The system is currently dominated by coal-fired generation technology, which accounts for about 65% of the total installed capacity. Solar PV follows coal-fired generation technology at about 15%, and then wind at 6%, gas at 5%, pumped storage hydro at 4%, nuclear at 3% and other small technologies share the remaining 2%. A detailed breakdown of the installed capacity by supplier is presented in the subsequent sections.

4.3.2 Eskom Existing Capacity

4.3.2.1 Eskom Installed Capacity

Eskom remains the dominant electricity generator in South Africa, accounting for approximately 75% of the country's total installed generation. The generation fleet has a total installed sent-out capacity of 48.3 GW and the breakdown of this capacity by technology type is shown in Figure 4 below.

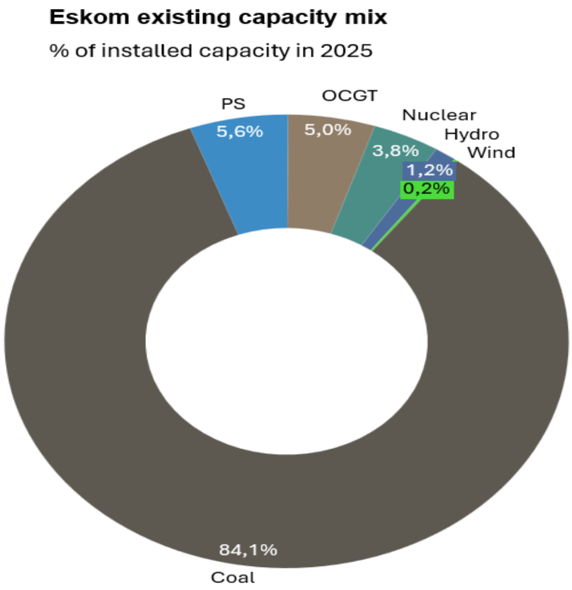

Figure 4: Existing Eskom fleet capacity.

Within the Eskom fleet, coal remains the primary generation technology, accounting for approximately 84% of Eskom's total capacity and 63% of the country's total capacity. This capacity includes Medupi Unit 4, which was successfully returned to service in July 2025 following a prolonged outage due to a generator stator explosion, and Kusile Unit 6 which achieved commercial operation in September 2025.

4.3.2.2 Eskom Fleet Shutdown

During the load shedding era in 2023, Eskom undertook a review of its planned coal fleet shutdown schedule, considering the prevailing energy security challenges that were evident. The review resulted in a revised position which supports the continued operation of coal-fired power stations that were originally scheduled for shutdown between 2023 and 2030. Consequently, Camden, Hendrina, Arnot, Grootvlei and Kriel are now expected to remain in operation until the end of 2028, after which their phased shutdowns will commence from 2029 in line with the revised shutdown schedule. The outcome of this review has been used as the generation shutdown position for the MTSAO 2025.

Furthermore, Eskom has undertaken a long-term operation project to extend the operation of Koeberg power station beyond its initial 40-year lifespan for another 20 years. This project includes replacing the steam generators to enable the long-term operation of the units. The necessary scope of works for Unit 1 was completed in December 2023, after which the National Nuclear Regulator (NNR) granted Eskom a license on 15 July 2024, permitting unit's continued operation until 2044. Extension work is currently underway for unit 2, whose license is set to expire in November 2025. The NNR concluded the public participation process on 06 October 2025, and a final decision on the extension is expected soon. The process for unit 2 is at an advanced stage with very minimal risk of non-approval. Consequently, MTSAO 2025 has assumed that both Koeberg Unit 1 and 2 are in operation for the entire study period.

The Eskom fleet that is expected to reach the end of its operational lifespan within the study horizon, and is scheduled for shutdown, is shown in Figure 5.

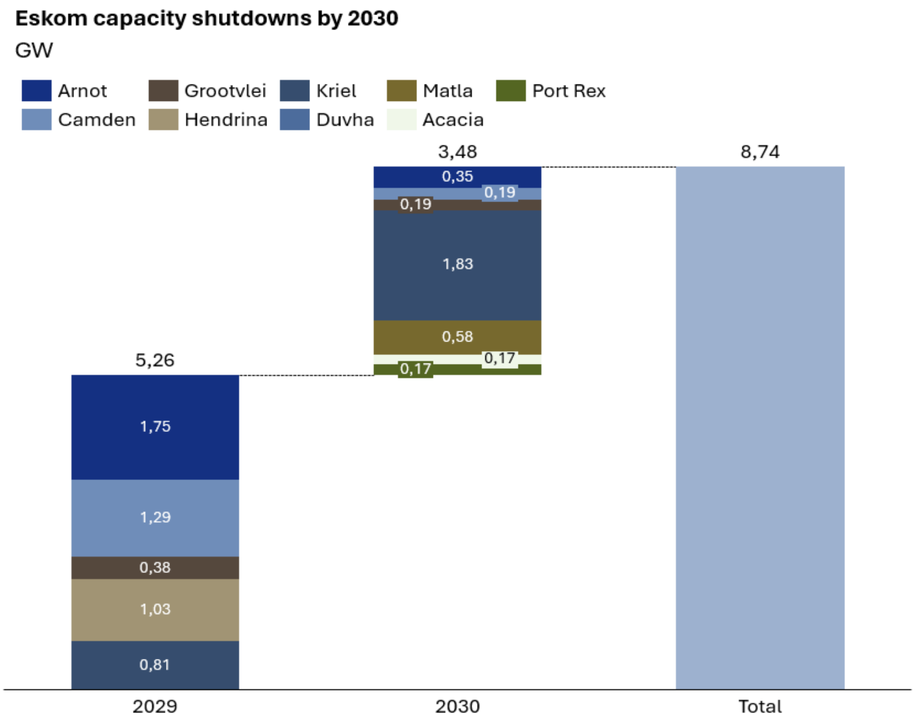

Figure 5: Capacity shutdown between 2025 and 2030.

Eskom's coal fleet capacity will decrease by 5.26 GW in 2029, due to the shutdown of units at various power stations as shown in Figure 4. A further 3.48 GW is projected to be shutdown in 2030, comprising of 3.14 GW coal units and 0.34 GW from Acacia and Port Rex OCGT plants. Consequently, a total of 8.74 GW is expected to be shutdown within the study period, of which approximately 96% is coal. This will reduce Eskom owned coal fleet from 40.1 GW to 31.7 GW (21% reduction).

4.3.2.3 Minimum Emission Standard Compliance

The previous MTSAO studies identified compliance with the Minimum Emission Standards (MES) as a critical risk to both system adequacy and overall security of supply. This is because the National Environmental Management: Air Quality Act (Act No. 39 of 2004) requires all Eskom coal and liquid-fuel fired power stations to comply with the MES regulations promulgated in the Act. As a result, Eskom lodged an application with the Department of Forestry, Fisheries and the Environment (DFFE) requesting postponement of certain air quality compliance timelines set out in the air quality legislation. Following a series of reviews, appeals and consultations, DFFE issued a final decision in May 2024 based on the recommendations of the National Environmental and Consultative Advisory (NECA) Forum. The ruling grants exemption to stations scheduled for shutdown by 31 March 2030, namely Arnot, Camden, Grootvlei, Hendrina and Kriel.

For all other stations, DFFE directed Eskom to submit further exemption applications, which Eskom did. The minister's ruling on additional exemptions, which was issued in March 2025 following the recommendations of the NECA Forum report of 8 March 2024, the expert report of 17 March 2025, and inputs from stakeholders including the Centre for Environmental Rights grants exemption for Kendal, Lethabo, Majuba, Matimba, Medupi and Tutuka until 31 March 2030, while Duvha and Matla are granted exemptions that are aligned with their planned shutdown dates of February and July 2034. Additionally, Eskom has an option to apply for further exemptions under extraordinary circumstances, which could allow continued operation beyond the current exemption period.

The risk of shutdowns due to MES non-compliance has not been considered in the study. Should the MES compliance targets not be met by the stations required to do so by 31 March 2030 and DFFE does not grant Eskom any further exemptions on these stations, available generation from the coal fleet will reduce by more than 22 GW from the affected stations and this will impact the system adequacy from 2030.

4.3.2.4 Eskom Plant Performance

The decline in Eskom plant performance in the past years resulted in frequent load shedding. However, the implementation of Eskom's Energy Availability Factor (EAF) recovery programme, which implements plant performance improvement projects at the worst performing stations while sustaining performance at the good performing stations has shown reliable performance, resulting in improved system performance and a significantly reduced frequency and severity of load shedding since the Financial Year (FY) 2024. In FY 2024, EAF improved from 55% to 61% compared to FY 2023, and load shedding was suspended for 348 days compared to just 32 days in the FY 2023. System performance for FY 2025 is sustained, with the year-to-date EAF (as of 10 October 2025) of 62.78% which is marginally lower than the 62.95% of the last financial year during the same period, and the company aspires to achieve an EAF of 70%.

MTSAO 2025 considered three scenarios namely low, moderate and high EAF. These scenarios are illustrated graphically in Figure 6.

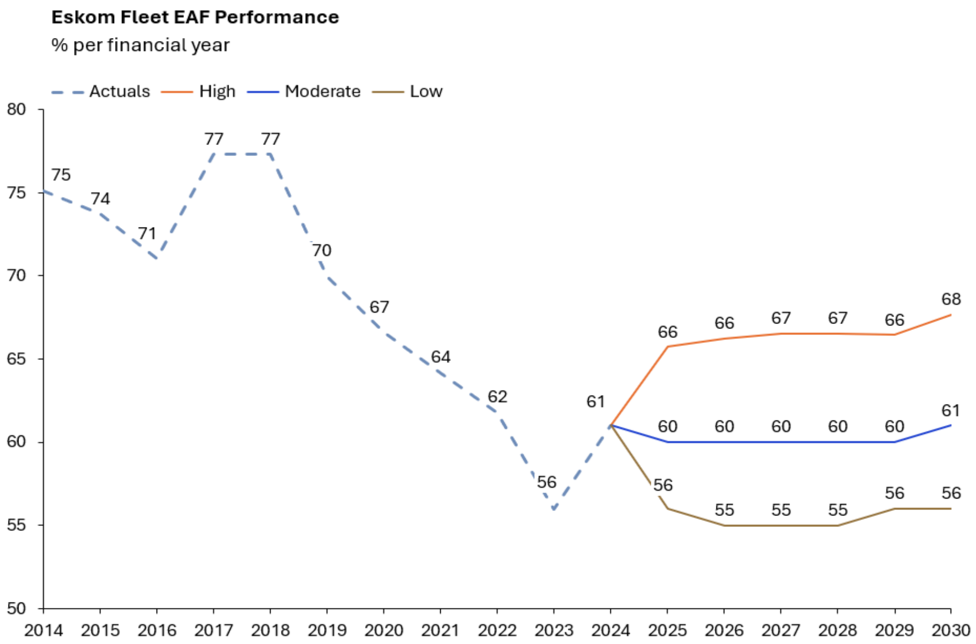

Figure 6: Historical and forecasted EAF performance for Eskom fleet.

The low EAF scenario represents a situation in which recovery initiatives fail to turn around the historical EAF trend. This scenario aligns with the draft IRP 2024 low EAF, adjusted to the FY 2024 actual of 61%, and reflects an annual average EAF of 55% over the study period. The moderate EAF represents a moderately optimistic recovery of EAF levels and is based on partial recovery initiatives. This scenario reflects an annual average EAF of 60% over the study period. The high EAF scenario represents an optimistic outlook where all recovery initiatives are fully effective, resulting in sustained improvements with an average EAF of approximately 67% over the study horizon.

MTSAO 2025 has adopted the moderate EAF projections for the study scenarios, as it reflects a moderate optimistic view and has conducted sensitivity analysis on the low and high EAF scenarios to assess their potential implications on the system.

4.3.3 Renewable and Risk Mitigation Independent Power Producer Programme

Figure 7 below shows the existing capacity from the Renewable Energy Independent Power Producer Programme (REIPPP), comprising of all projects from Bid Window (BW) 1 to 4, as well as 0.28 GW of capacity from BW 5 that recently went into commercial operation. The figure also includes committed capacity from the Risk Mitigation Independent Power Producer Procurement Programme (RMIPPPP). Notably, the utility scale renewable generation capacity in commercial operation, has increased from 0.47 GW in 2013 to 6.72 GW in September 2025, representing a fourteen-fold increase over the period. This rapid growth reflects the country’s commitment to integrating clean energy sources onto the grid in order to diversify the generation portfolio away from the conventional fossil fuel-based generation sources, which currently dominate the system.

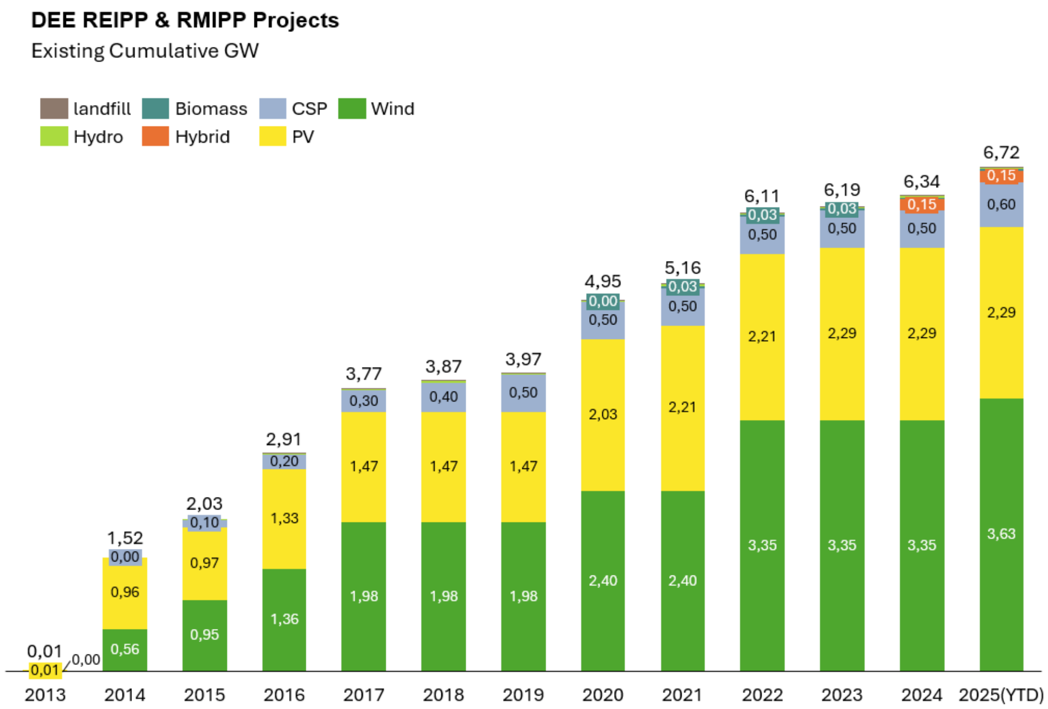

Figure 7: REIPPP and RMIPPP cumulative capacity.

4.3.4 Non-Eskom generators

Non-Eskom generators that are licensed by NERSA and are connected to the grid (excluding Avon, Dedisa and the Cahora Bassa hydro import), amount to 2.4 GW and contribute about 10.5 TWh, as outlined in Table 2 below. The study has accounted for this capacity and due to the unavailability of detailed data for non-Eskom power plants, the MTSAO assumed typical plant performance based on facilities of a similar type, size and age. In addition, similar energy production based on historical performance has been assumed for the future. Any unforeseen decline in the generation of these technologies will have a negative impact on power system adequacy.

Table 2: Non-Eskom capacity and energy

Technology Name	Capacity (MW)	Energy (TWh)
Coal	1328	5.60
Gas	582	3.08
Cogeneration	198	1.39
Pumped Storage	180	0.15
Hydro	31	0.14
PV	36	0.07
Wind	7	0.01
Biogas	17	0.03
Biomass	8	0.07
Total	**2387**	**10.54**

Non-Eskom capacity also includes the (i) 0.42 GW (0.24 GW PV, 0.16 GW wind and 0.02 GW others) capacity from private initiatives that are already operational (ii)1.01 GW from the DEE peaking plants namely Dedisa and Avon, whose contracts expire in August and September 2030 and (iii) 1.15 GW from the Hydro Cahora Bassa (HCB) whose current contract is set to expire in March 2030. DEE Peakers and HCB plant are optimised based on their availability, system needs and contractual constraints.

4.3.5 Small-Scale Embedded Generation

The lack of centralised validated data remains a challenge in determining the full extent of Small-Scale Embedded Generation (SSEG) installations, which are rooftop solar PV and ground-mounted small PV plants. The System Operator data indicates that the embedded generation could be as high as 6.9 GW currently (System Operator Weekly System Status Week 40 of 2025). The historical installations of the systems are shown in Figure 8 below.

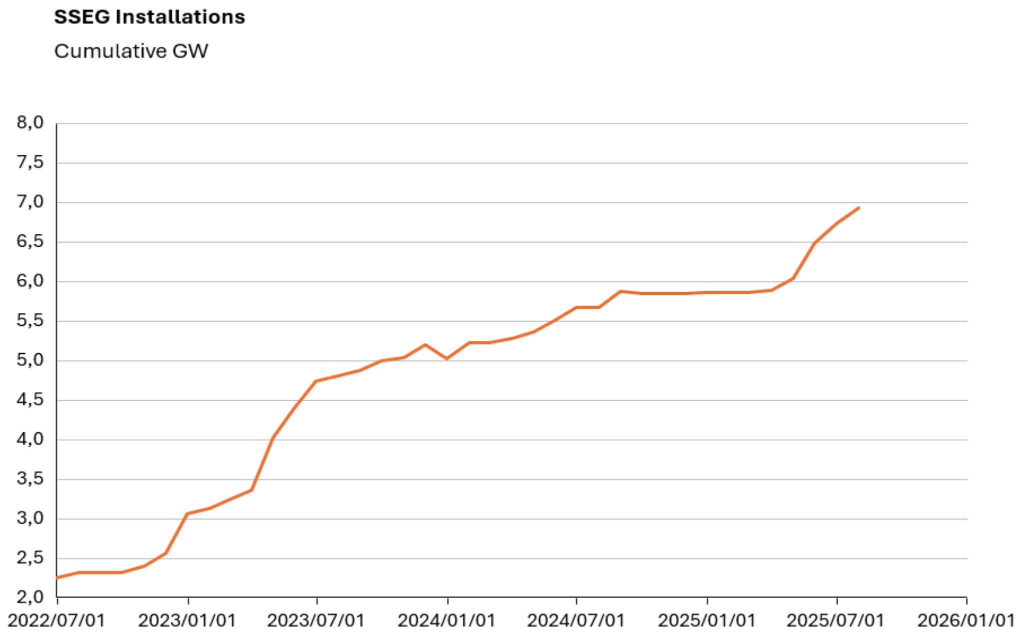

Figure 8: SSEG historical installations.

The SSEG installations increased significantly during high levels of load shedding, driven primarily by the need for a back-up supply to reduce the impact of load shedding. However, the installation of these systems has slowed down ever since the frequency and severity of load shedding reduced, which in turn reduced the urgent need for the installation of SSEGs. The high capital cost associated with the installation of these systems specifically within the residential sector, also results in continued installations being among the high-income earners, many of whom were the early adopters of the rooftop PV systems. The slower growth could therefore also indicate emerging market saturation.

4.4 New Generation Capacity

4.4.1 Eskom Renewable Energy Projects

As part of the company's commitment to increase its share of renewable energy generation and to repurpose some of the old coal power stations, Eskom has a pipeline of projects that are under consideration and development. Only projects with a high probability of reaching commercial operation within the study horizon have been considered. These projects are a combination of wind, solar PV and Battery Energy Storage System (BESS) and they are shown in Figure 9 below. The projects amount to 1.89 GW and BESS accounts for most of this capacity at 47%, followed by a substantial solar PV at 39% and the remaining 14% is contributed by wind.

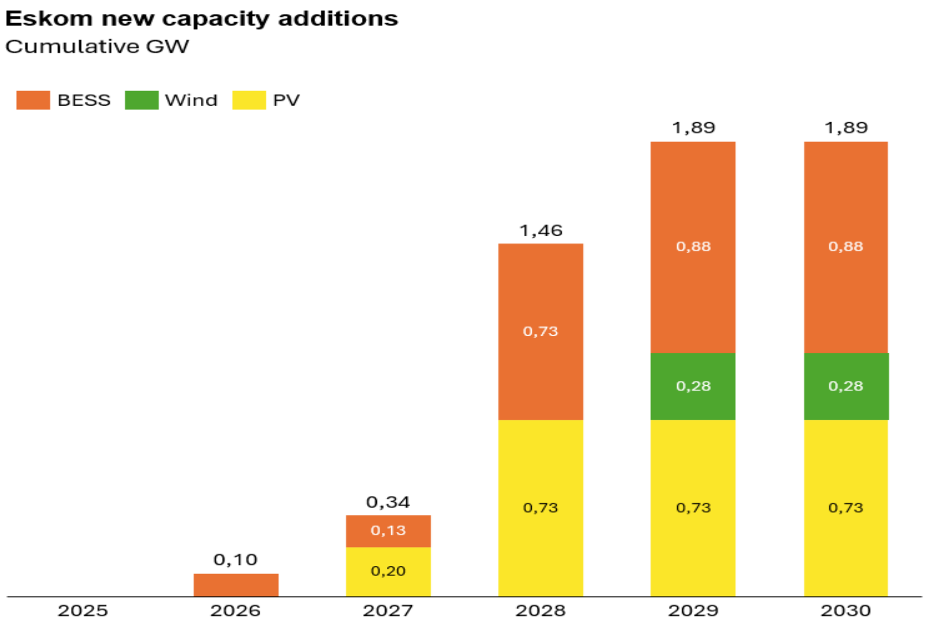

Figure 9: Eskom's new RE projects.

4.4.2 Renewable Independent Power Producers Programme

The MTSAO study assumed a cumulative capacity from the REIPPP up to BW 7 and the committed RMIPPPP.

In addition to the existing REIPPP and RMIPPP capacity shown in Figure 7, new additional capacity is planned under this programme and is shown in Figure 10 below. This additional capacity of 4.57 GW, combined with the existing 6.72 GW, results in a total installed cumulative capacity of 11.29 GW over the study period. Solar PV accounts for the largest share at 54%, followed by wind at 37%, CSP at 5% and hybrid at 4%, with minimal contributions from biomass, hydro, and landfill gas.

In terms of the project progress, two BW 5 projects with a total capacity of 0.28 GW are already in commercial operation and are accounted for under the existing capacity, and the remaining projects under BW 5 are in construction and are expected to reach commercial operation by the end of 2025. BW 6 and RMIPPP projects are also in construction and are anticipated to reach commercial operation between 2025 and 2026. BW 7 projects have all received the preferred bidder status and are anticipated to reach commercial operation from 2027 onwards.

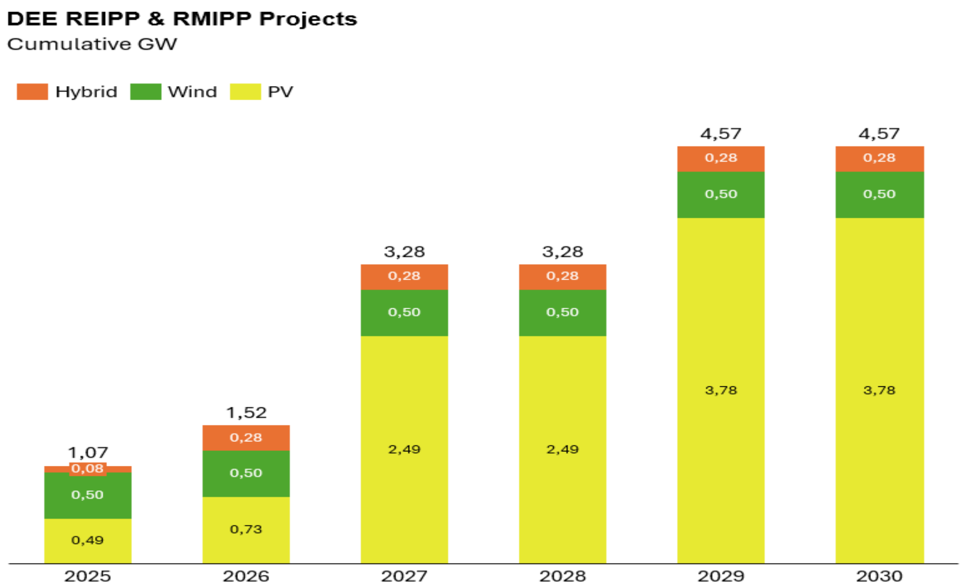

Figure 10: Renewables capacity from REIPP BW 5 to 7 and RMIPP

4.4.3 IPP Battery Energy Storage System

The MTSAO study assumed a cumulative battery energy storage capacity from the Energy Storage IPP Bid Windows 1 to 3. The cumulative capacity from all Energy Storage IPP bid windows is illustrated graphically in Figure 11.

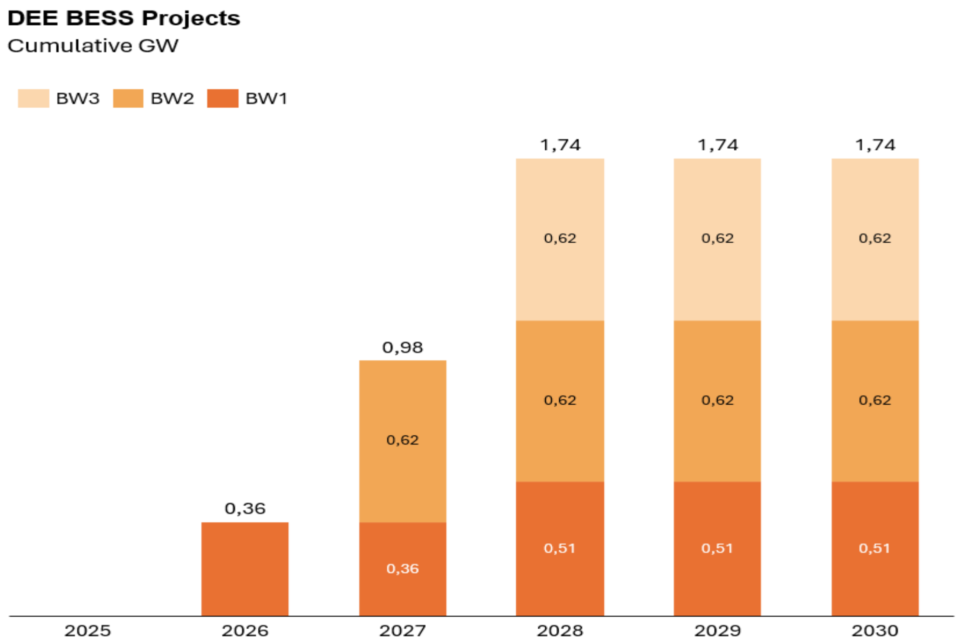

Figure 11: Batteries from Independent Power Producers

Four projects under BW 1, totalling to 0.36 GW are currently under construction and are expected to reach commercial operation in 2026. The remaining project under BW 1, with a capacity of 0.15 GW is anticipated to achieve commercial operation by 2028. The extended timeline for this project is due to a revised scope that now includes the construction of a new substation. For BW 2, eight preferred bidders were announced in December 2024, with commercial operation expected by August 2027. Similarly, projects in BW 3, which consist of five preferred bidders announced in May 2025, are expected to reach commercial operation by January 2028.

4.4.4 Gas to Power Generation

The study also considered the 6 GW gas to power projects, which are viewed as key enablers for the establishment of the gas infrastructure to support the energy needs of various sectors within the country. These projects are envisaged to be of the Combined Cycle Gas Turbines (CCGT) type. Eskom will own 3 GW of this capacity, while the remaining 3 GW is the Gas IPP Bid Windows 1 and 2. The study assumed that these projects would reach commercial operation by 2030. Given that the commissioning timelines of the 6 GW CCGT capacity coincide with the planned shutdown of Eskom's 8.4 GW coal fleet and the expiry date of the HCB contract, the risk associated with the delayed commissioning of CCGT capacity was studied as a sensitivity to evaluate its implications on system adequacy.

4.4.5 Power Generation Initiatives by the Private Sector

Several utility-scale private renewable energy power plants are either connected or in the process of connecting to the national grid in South Africa. These projects aim to either supply power for self-consumption, helping customers reduce their energy costs, or facilitate wheeling agreements where energy is transmitted through the grid to private customers. In addition to the 0.42 GW capacity already operational, several new projects from this programme are in progress and in various stages of development.

The MTSAO only considered projects that are in the Budget Quote (BQ) stage and beyond, as these are the projects that have reached a more advanced level of planning and commitment and have a high integration potential to the grid. These projects amount to 11.5 GW and consist of 7 GW PV, 4.4 GW wind and a combined capacity of 0.1 GW from biogas, biomass and hydro. The cumulative capacity of the new projects within the study period is shown in Figure 12. This additional capacity of 11.5 GW and existing capacity of 0.42 GW results in a total installed capacity of 11.9 GW over the study period.

A total capacity of 4.1 GW (1.8 GW PV, 2.3 GW wind and 0.02 GW from others) is already in construction and is expected to reach commercial operation from 2026. An additional capacity of 1.2 GW (0.7 GW PV and 0.5 GW wind) has issued BQs which are awaiting acceptance, and these projects are anticipated to reach commercial operation by 2028. Furthermore, projects totalling to 6.2 GW (4.5 GW PV, 1.7 GW wind and 0.01 GW Others) are in the BQ development phase and are expected to reach commercial operation by 2029.

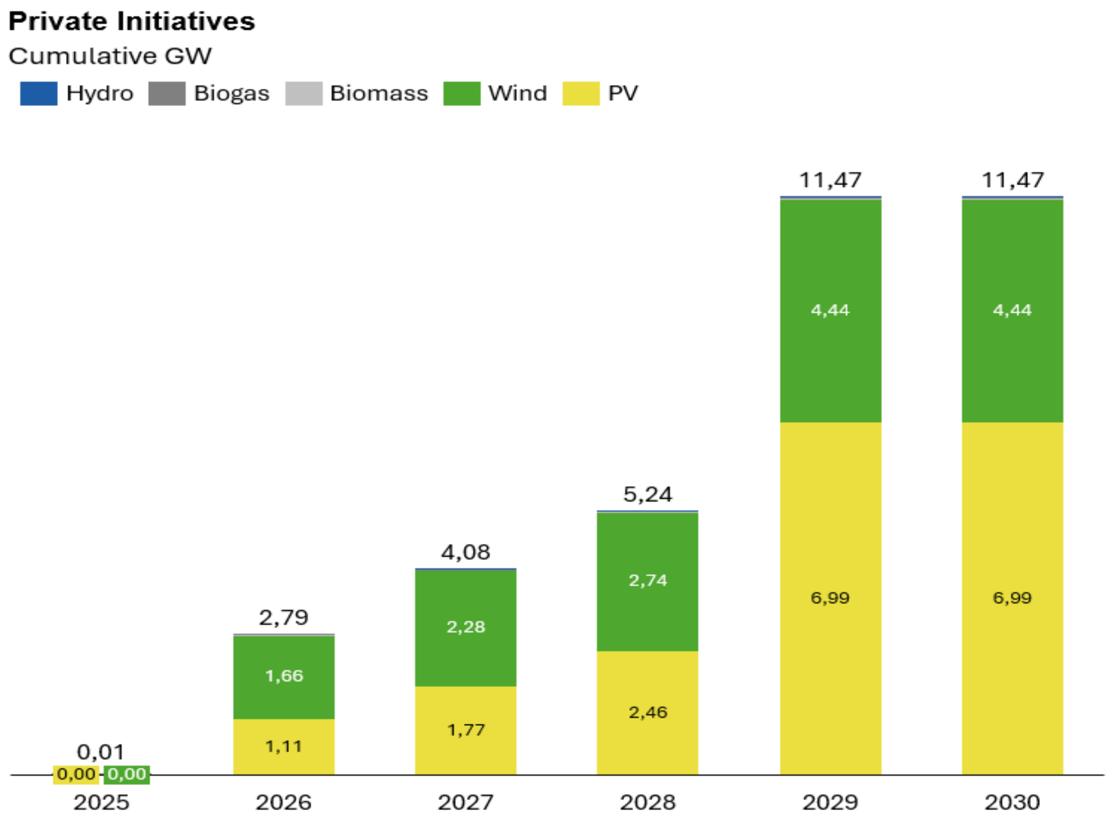

Figure 12: Private Sector Generation Initiatives

4.4.6 Small Scale Embedded Generation

The MTSAO has considered two projections for the study horizon namely low and high penetration levels of SSEGs. The low penetration level is based on statistical projections following the recent low penetration levels after the reduced frequency and severity of loadshedding, and corresponds to an average growth rate of 0.27 GW per annum. The high penetration level is based on the revised 2025 GreenCape's projection of 0.54 GW per annum within the study horizon. Consequently, the low and high penetration scenarios are expected to result in an additional 2.2 GW and 3.8 GW of SSEGs being added to the grid over the study period.

The study has adopted both scenarios to capture a range of potential outcomes, with conservative scenarios such as the base case adopting the low projection, while other scenarios incorporate the high projection of SSEGs.

5. NEW GENERATION CAPACITY CATEGORISATION

Given the inherent uncertainty surrounding some of the projects considered for the MTSAO 2025, the study has grouped them into distinct categories to represent various potential outcomes for future capacity development. These categories are committed new capacity, all new capacity, risk-adjusted new capacity, and accelerated build new capacity, each reflecting different levels of project readiness and likelihood of success.

5.1 Committed New Generation Capacity

Committed capacity consist of projects that are in construction from the various programmes. In addition, this capacity includes the 6 GW CCGT projects, which even though they are not yet in construction, are considered committed due to their strategic importance within the national energy framework. The capacity in this category is shown in Figure 13 below. The study has included this capacity as part of the base, and it reflects a growth from 1.9 GW in 2025 to 14.8 GW by 2030. This capacity is 8.1 GW higher than the new capacity that was included in the MTSAO 2024 base. The reason for this significant increase is that many of these projects, which previously had uncertain commercial operation dates in the MTSAO 2024, now have a much greater certainty due to their advanced stages of development. The differences are mostly in the private initiatives, which have grown from 2.7 GW in MTSAO 2024 to 4.1 GW in the current study and the 6 GW CCGT projects, which did not form part of the base capacity in MTSAO 2024.

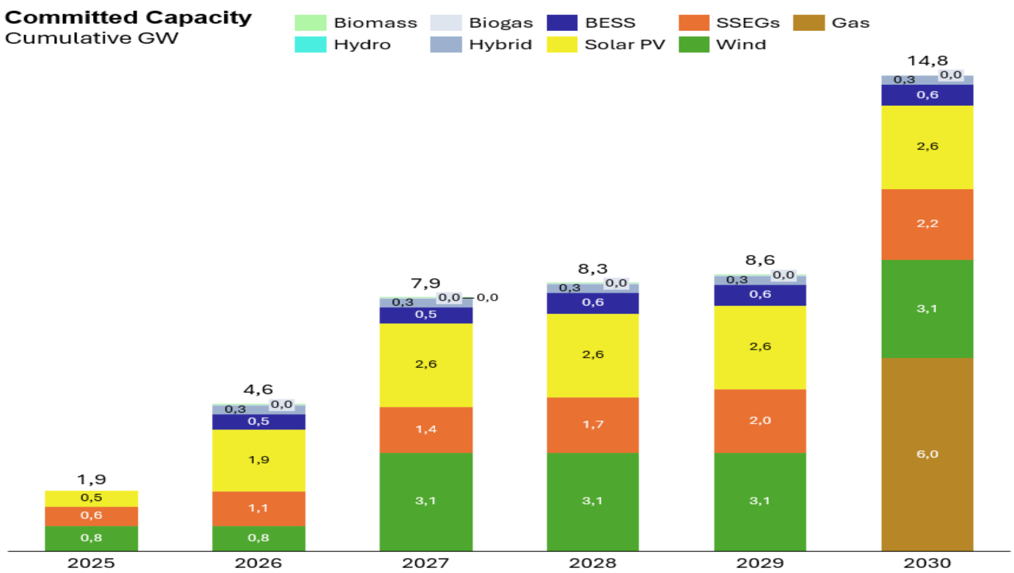

Figure 13: Committed New Capacity

5.2 All New Generation Capacity

All new capacity consists of all the projects from various stages of development. This category captures a broader range of initiatives, and its capacity grows from 2 GW in 2025 to 29.7 GW in 2030. This capacity is 2.8 GW higher than the capacity considered in the MTSAO 2024 for the same category. The differences are mostly on the (i) gas capacity, which the previous MTSAO only considered 3 GW compared to the 6 GW considered in this study (ii)private initiatives, which have grown from 8.7 GW in MTSAO 2024 to 11.5 GW (iii) BW 7 capacity, which has reduced from 5 GW to 3.1 GW and (iv) SSEG capacity which has reduced from 4.5 GW to 3.8 GW. A breakdown of this capacity by technology is shown in Figure 14 below.

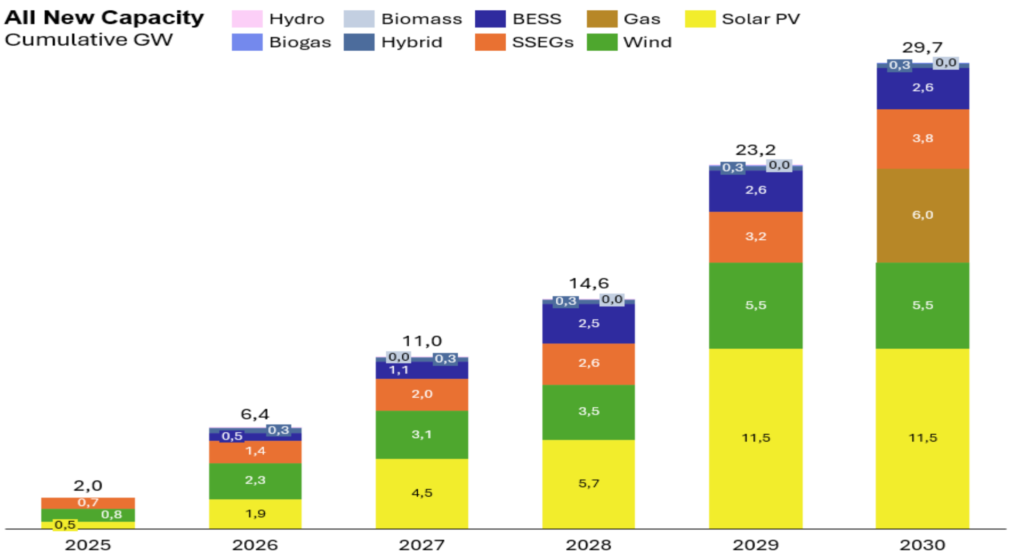

Figure 14: All New Capacity

5.3 Risk Adjusted New Generation Capacity

Risk-adjusted capacity represents a selection of projects based on sensitivity analysis. Unlike the broader all-new capacity category, which includes projects across various development stages, the risk-adjusted category narrows the focus to those projects with a stronger probability of achieving commercial operation within the study period. The capacity in this category is shown in Figure 15 below.

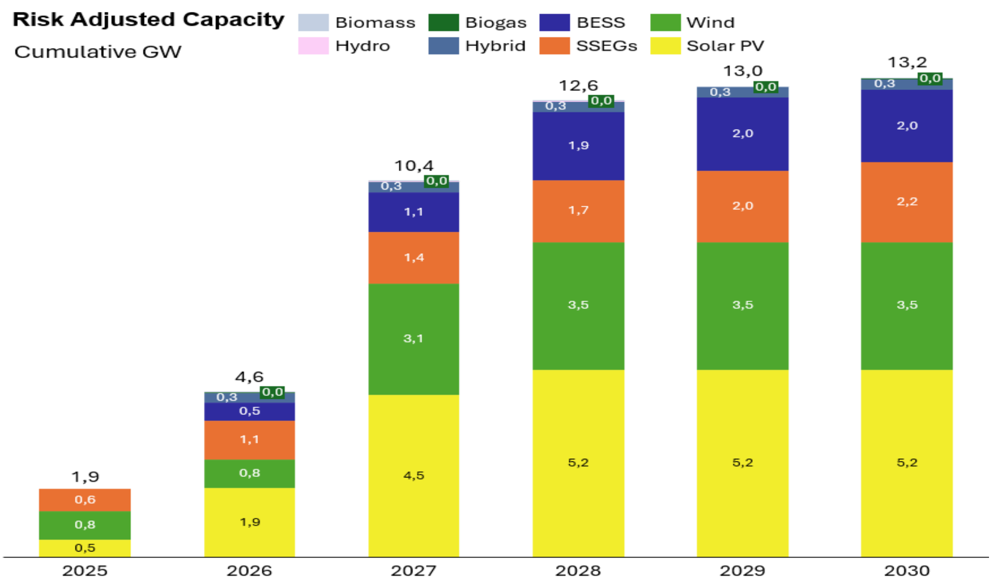

Figure 15: Risk-adjusted New Capacity

The category differs from the committed capacity in that it also includes the BW 7 projects, private initiatives with issued BQs, BESS BW 2 and 3, Eskom projects currently at the design stage, and excludes the 6 GW gas to cater for risks associated with delays. The capacity under this category grows from 1.9 GW in 2025 to 13.2 GW in 2030.

5.4 Accelerated Build New Generation Capacity

Accelerated build new capacity consists of all the projects considered under the all-new capacity category. However, this capacity includes the additional 4.7 GW from private initiative generation projects that recently attained BQ status, resulting in the business initiatives new capacity increasing from 11.5 GW (all-new category) to 16.2 GW. Increased capacity and accelerated timelines from the private initiative projects are the only differences between all-new and accelerated build categories. This additional capacity from the business initiatives results in the total capacity considered in the MTSAO increasing from 29.7 GW to 34.4 GW, and a breakdown of this capacity by technology is shown in Figure 16 below.

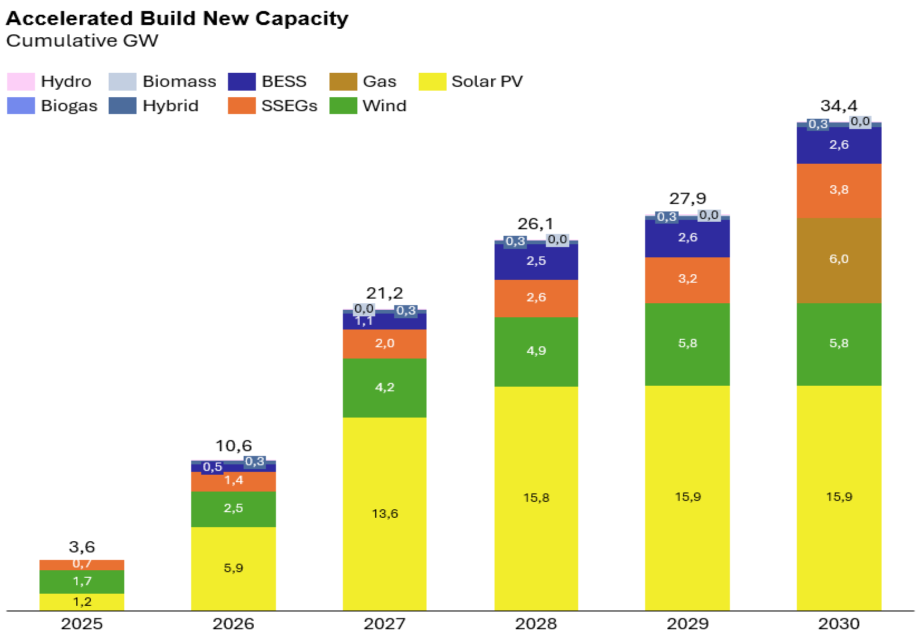

Figure 16: Accelerated Build New Capacity

6. STUDY CASES

The studied scenarios were selected based on the most probable outcomes related to future generation capacity development, as outlined in Section 5. The MTSAO study considered 4 scenarios namely the base case, risk-adjusted, all planned and accelerated build scenarios and they are presented in Figure 17 below.

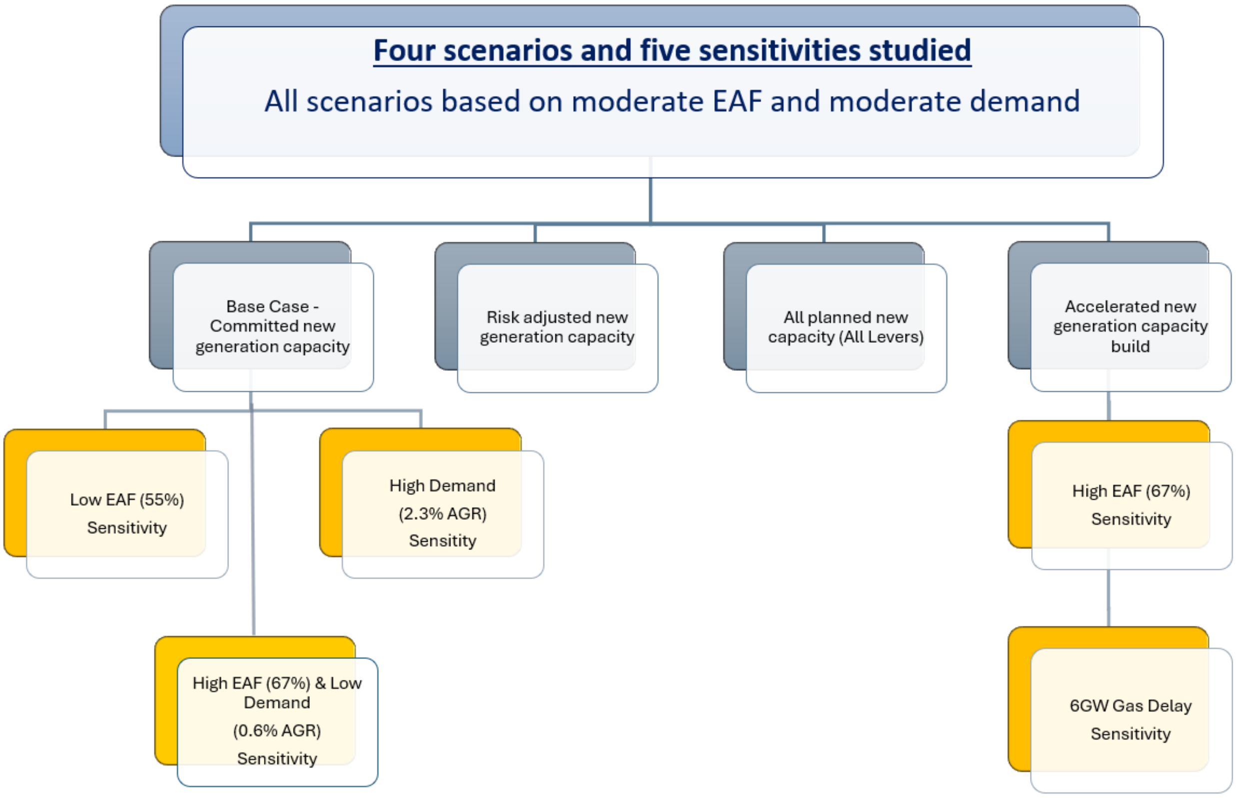

Figure 17: Studied scenarios and sensitivities.

The main scenarios are based on moderate demand and moderate EAF, with the primary distinction being the additional capacity considered. These capacities correspond to the categories described in Chapter 5, and the scenario names align with the respective category descriptions.

Additionally, the study includes sensitivity analysis on base case capacity, which is derived in three forms namely (i) changing the base case EAF from moderate to low (ii) changing moderate demand to high demand and (iii) changing both moderate EAF and moderate demand to high EAF and low demand respectively. It also includes sensitivity analysis on the accelerated build scenario, with EAF variation from moderate to high and 6 GW delay in gas capacity.

7. STUDY OUTCOMES

7.1 Unserved Energy

7.1.1 Scenario-Based Analysis

The expected unserved energy from different scenarios over the five-year study horizon is shown in Figure 18.

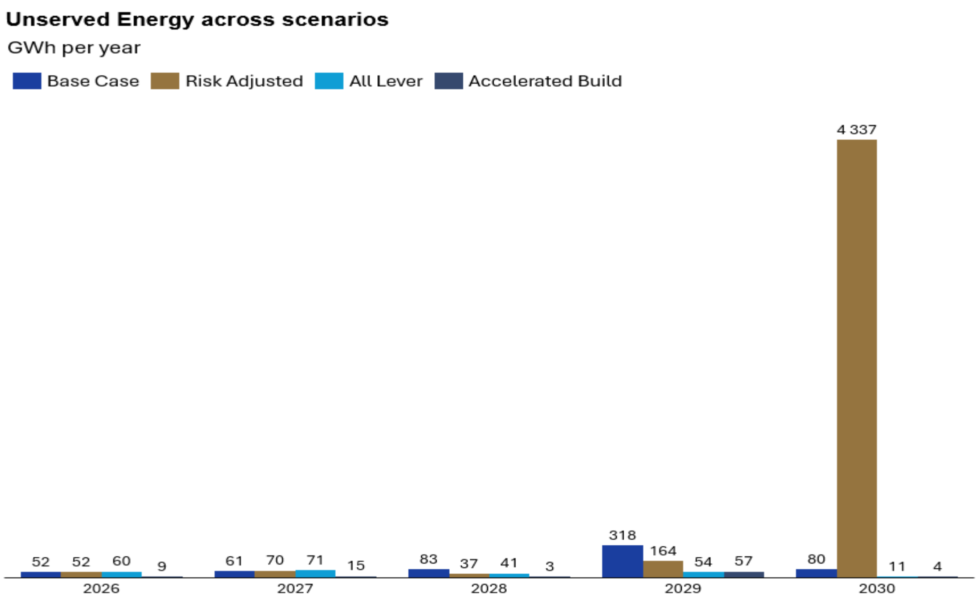

Figure 18: Unserved Energy

The unserved energy across all scenarios is within the levels that can be managed operationally through levers available within the System Operator without posing significant system risks.

The unserved energy starts showing increased levels in 2029 and this is caused by the retirement of 5.26 GW of coal capacity, which introduces a temporary supply gap and pushes unserved energy upwards. This shortfall is mitigated in 2030 by the introduction of 6 GW of new CCGT capacity, which provides the necessary system relief and reduces unserved energy to manageable levels. However, the risk-adjusted scenario which assumes the CCGT gas capacity is delayed and does not come within the study period, reflects a substantial increase in unserved energy in 2030. The gap created by the shutdown of baseload capacity without adequate replacement is therefore a key factor contributing to the observed rise in unserved energy. These results highlight the importance of alignment between coal capacity shutdowns and CCGT commercialisation and they are consistent with the observations highlighted in the draft IRP 2024.

7.1.2 Unserved Energy Composition

Unserved energy can be caused by inadequacy of the generation system to meet demand, and transmission constraints which restrict the delivery of available generation to key load centres. The distribution of unserved energy between generation and transmission constraints is shown in Figure 19 below. This distribution excludes the accelerated build scenario, however, it should be expected that the transmission constraint challenges would be exacerbated with this scenario.

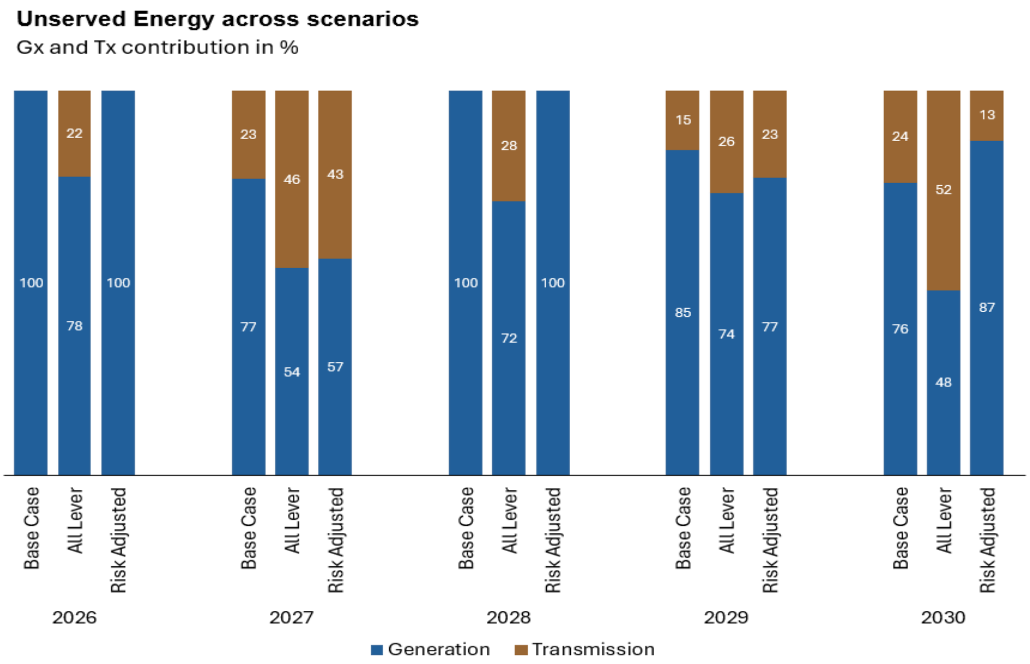

Figure 19: Generation and transmission contribution to unserved energy.

Generation inadequacy is the primary driver of unserved energy across scenarios and years. In some cases, however, transmission constraints further exacerbate the situation by limiting the ability to deliver available generation to key load centres. These transmission constraints are not significant in most scenarios, and grid strengthening projects are already underway to alleviate congestions in constrained regions. Examples include the establishment of the Kyalami MTS to deload Lulamisa MTS in the Gauteng region, and the establishment of the 400/132 kV 2 × 500 MVA Bighorn MTS to relieve the existing 275/88 kV 3 × 315 MVA MTS in the Northwest region, both of which are some of the MTSs with high levels of unserved energy. The commercial operation dates of these projects fall outside the study horizon.

It should be noted that the planning and implementation of transmission expansion initiatives fall under the TDP, which should be consulted for detailed information and project implementation timelines. In the interim, transmission limitations can be partially managed through System Operator flexibility measures, including but are not limited to, network sectionalisation and the application of contingency limits where applicable, to minimise unserved energy until permanent reinforcements come online.

7.1.3 Worst Unserved Energy scenario

The monthly unserved energy analysis from the scenario with the worst unserved energy (risk adjusted scenario in 2030) is shown in Table 3 below.

Table 3: Monthly unserved energy

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
1	1.04	0.53	1.41	1.56	1.01	1.25	0.87	1.58	1.95	11.71	13.22	28.60
2	1.12	0.58	1.57	2.02	1.33	1.58	1.19	2.17	2.53	14.11	15.45	30.38
3	2.15	1.13	3.11	5.21	4.02	3.67	4.73	7.38	6.14	27.28	26.91	36.44
4	5.33	3.74	8.69	18.08	18.29	13.64	19.69	23.82	14.01	59.77	51.15	46.08
5	6.20	5.76	12.86	30.71	32.94	23.64	33.74	41.28	25.01	66.24	42.00	35.95
6	3.20	2.13	7.94	19.70	29.03	37.36	39.91	40.17	16.13	30.19	18.46	21.92
7	2.04	0.69	2.78	5.56	10.64	29.82	15.15	15.00	4.68	10.56	7.59	10.96
8	0.83	0.12	0.36	0.54	1.50	14.21	2.15	3.78	0.84	3.52	3.41	5.14
9	0.40	0.02	0.08	0.02	0.24	4.70	0.22	0.81	0.09	1.26	1.37	2.30
10	0.23	0.01	0.02	0.00	0.03	1.68	0.00	0.29	0.02	0.62	0.93	1.32
11	0.10	0.00	0.02	0.00	0.01	0.78	0.00	0.14	0.00	0.48	0.85	1.33
12	0.06	0.00	0.02	0.00	0.01	0.56	0.00	0.14	0.00	0.35	0.61	0.85
13	0.05	0.00	0.02	0.01	0.01	0.33	0.00	0.28	0.03	0.39	0.71	0.78
14	0.06	0.00	0.04	0.01	0.02	0.94	0.02	0.29	0.06	0.78	1.49	1.59
15	0.05	0.00	0.04	0.79	3.95	15.72	4.52	1.72	0.58	2.79	3.12	2.66
16	0.17	0.04	1.98	32.98	47.23	67.19	52.87	34.58	22.83	28.86	9.52	6.90
17	4.25	3.26	13.45	52.34	64.45	91.66	89.03	65.74	42.32	87.40	61.60	60.80
18	8.10	6.02	14.93	42.57	44.99	81.27	89.56	77.85	49.28	105.16	87.54	95.63
19	7.71	4.74	9.61	27.48	29.42	58.83	62.65	55.62	35.00	84.22	72.87	93.72
20	4.30	2.38	4.98	13.33	13.37	31.02	30.57	27.50	16.91	49.63	44.11	67.05
21	1.69	1.12	2.47	5.21	4.78	10.95	9.85	9.57	6.92	25.71	24.82	47.17
22	1.28	0.70	1.94	3.57	3.05	5.21	4.56	5.33	4.64	20.21	20.35	42.12
23	1.32	0.76	2.04	3.46	2.86	5.04	4.49	5.51	4.75	20.39	21.39	43.68
0	1.13	0.55	1.42	1.90	1.39	1.86	1.33	2.29	2.65	13.69	15.85	31.79

Unserved energy is expected predominantly during morning and evening peak hours, highlighting the system's inability to meet demand when it is at its highest. In addition, unserved energy intensifies significantly from April 2030 because of the decommissioning of an additional 3.14 GW of coal capacity by March 2030 on top of the 5.26 GW decommissioned in 2029, which removes a significant portion of firm generation from the system. The expiration of the HCB contract in March 2030 further exacerbates the problem due to the removal of 1.15 GW from the system. The cumulative removal of approximately 9.5 GW capacity in two years, without any appropriate and timely replacement, will result in a significant supply gap.

7.1.4 High Unserved Energy Week

The week with the highest unserved energy from the risk-adjusted scenario in 2030 is shown in Figure 20 below. The coal generation profile is predominantly flat throughout the week, indicating maximum utilisation of available capacity. Solar generation output during the day alters the conventional demand pattern, which is expected to exhibit distinct morning and evening peaks, due to the charging of storage systems. The charging increases the midday demand to prepare the system for the evening period, when customer load is at its highest. There is also high utilisation of OCGTs for most of the week, operating almost as baseload stations rather than peaking stations to reduce the energy gap levels.

Pumped storage schemes and BESS primarily come online in the morning and evening peaks to help curb the situation, however, even their deployment is not enough to close the gap, resulting in the gap that goes as high as 6 GW on some days, with an average of 1.5 GW during unserved energy hours over the week analysed. These results indicate that even with maximum utilisation of all the generation resources available within the system, significant operational constraints and heightened system security risks are expected if no new firm generation is deployed to close the gap during peak hours, highlighting the critical role that new CCGT capacity is expected to play in closing the energy deficit and enhancing system adequacy.

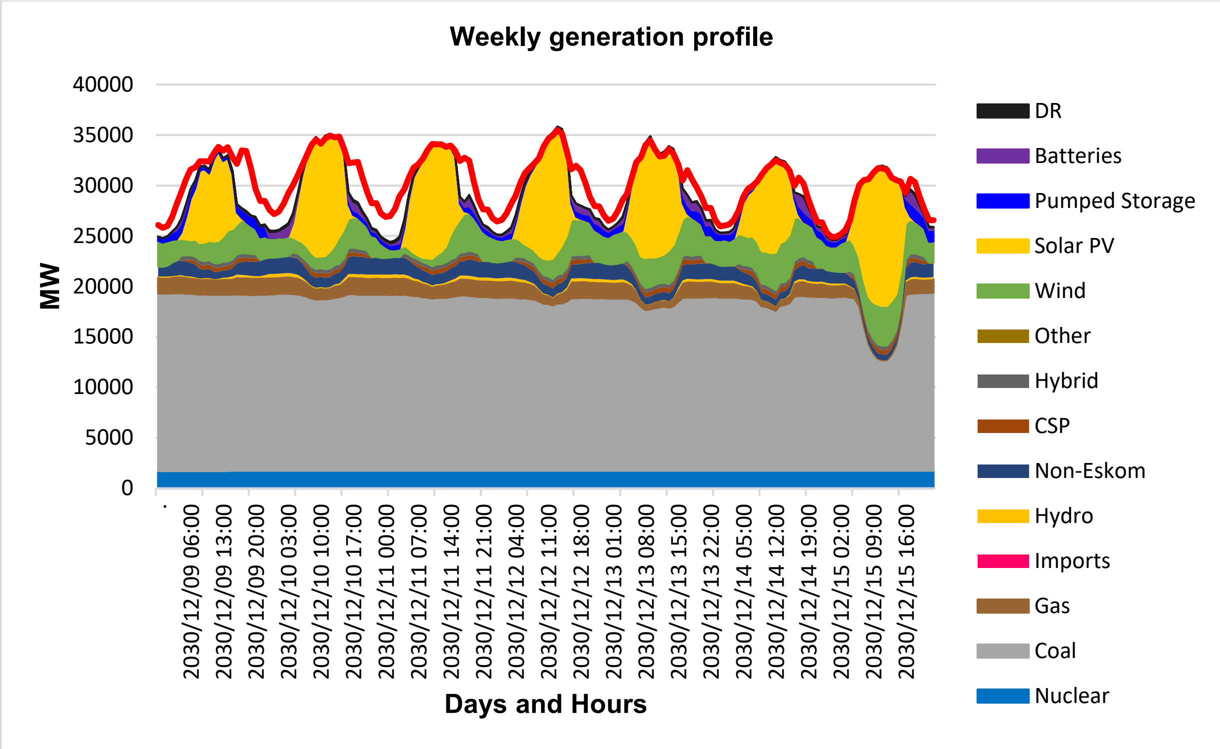

Figure 20: Weekly highest unserved energy from risk-adjusted 2030.

7.2 OCGT Utilisation

The expected OCGT utilisation from different scenarios over the five-year study horizon is shown in Figure 21.

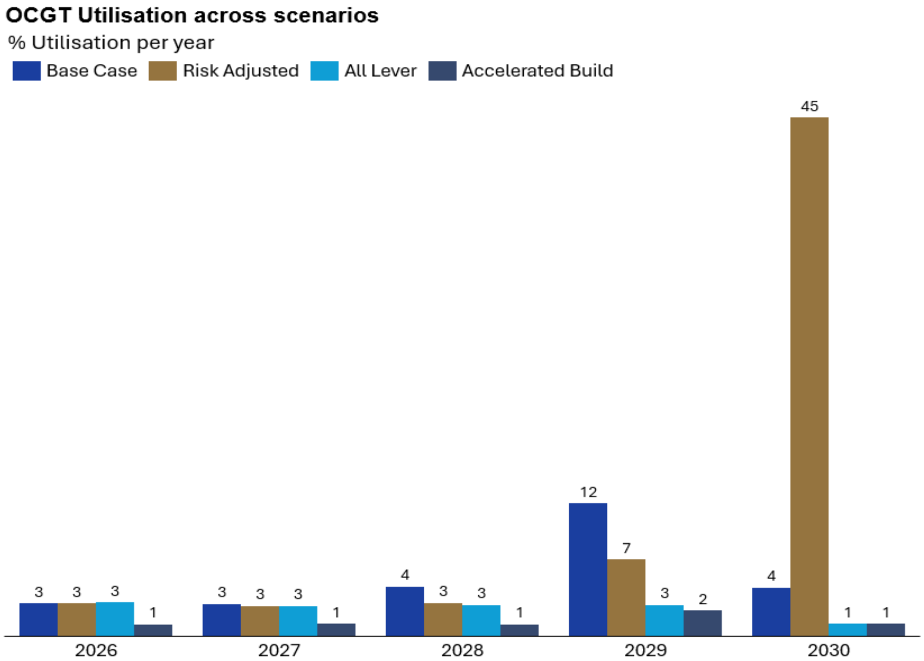

Figure 21: OCGT Utilisation

OCGT utilisation is minimal across all scenarios for most of the study period, remaining way below the 6% adequacy metric. A noticeable increase is observed in 2029, particularly in the base case and risk-adjusted scenarios, due to the shutdown of coal units. The commissioning of new CCGT capacity in 2030 subsequently reduces reliance on OCGTs, except in the risk-adjusted scenario where commissioning delays result in higher utilisation. This observation further strengthens the need to align coal capacity shutdowns with the commercialisation of CCGT new capacity, as the misalignment not only results in elevated levels of unserved energy but will also necessitate extensive use of OCGTs to reduce the severity of system inadequacy.

Furthermore, transmission constraints marginally increase OCGT utilisation by restricting power transfers and creating localised shortages that necessitate additional OCGT dispatch. For most scenarios and years, this increase is approximately 1% except in the risk adjusted scenario in 2030, where the increase is about 6%. This highlights the importance of a coordinated new generation integration with timely commercialisation of grid initiatives to ensure that network limitations do not force reliance on OCGTs to meet regional energy deficits caused by grid congestion.

7.3 Excess Energy

7.3.1 Scenario-Based Analysis

The expected excess energy from different scenarios over the five-year study horizon is shown in Figure 22 below.

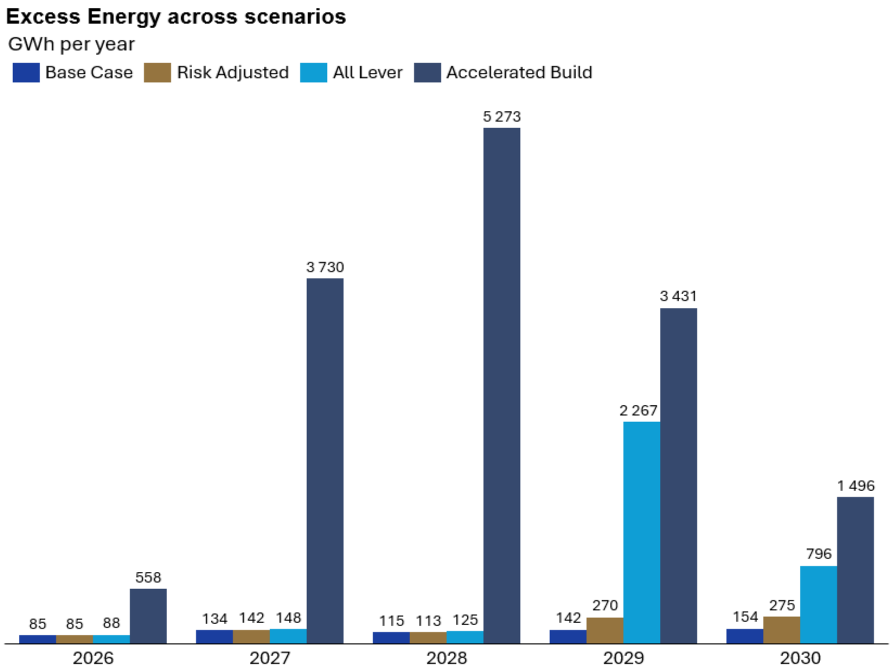

Figure 22: Excess Energy

Excess energy is observed across all scenarios and years of the study period. However, the level of excess energy remains moderate for all scenarios, except in the all-lever and accelerated build scenarios, where higher values are recorded.

Higher levels are observed in the all-lever scenario in 2029, primarily driven by the addition of approximately 9 GW of new generation capacity relative to 2028, of which about 60% is solar PV installations, inclusive of both the utility-scale plants and SSEGs. The decommissioning of 5.26 GW of coal capacity in 2029 partially offsets this increase, as the removal of minimum committed capacity from these plants reduces the extent of excess energy that would have otherwise been experienced by the system. The excess energy declines significantly in 2030 compared to 2029 because of the (i) continued growth in demand, which absorbs a portion of the excess energy (ii) decommissioning of an additional 3.14 GW of coal units which further removes the minimum committed capacity from coal and (iii) removal of 1.15 GW of capacity due to expiration of CHB contract.

Increased generation from private initiatives, as well as the accelerated integration timelines, further exacerbates the situation, as demonstrated by the accelerated build scenario. The addition of new capacity, coupled with earlier commercial operation dates, results in high levels of excess energy being experienced much earlier than 2029, with the highest levels anticipated in 2028. The impact of coal capacity shutdowns in 2029 and 2030, coupled with increasing demand is also evident in this scenario, hence there is reduced excess energy in these years.

7.3.2 Excess Energy Composition

Excess energy can be caused by over subscription of generation relative to the demand, requiring certain generators to have their generation output reduced, a condition that is referred to as dump energy. Excess energy can also be caused by the transmission grid's ability to deliver power to key load centres, resulting in generation curtailment. The distribution of excess energy between generation and transmission is shown in Figure 23 below.

Transmission network inadequacy is the primary driver of excess energy across most scenarios and study years, except in the all-lever scenario in 2029 and 2030, where excess energy primarily results from an oversupply of generation relative to system demand. Excess energy indicates periods when generation availability exceeds the demand, resulting in continued supply to the grid even when it is not required. This highlights the lack of flexibility on the power system, as it is currently characterised by the high share inflexible generation and self-dispatching variable generators with limited storage, leading to inefficient utilisation of available generation and suboptimal mix.

The regions experiencing significant network constraints already have plans in place to address these challenges. For instance, the Port Elizabeth (PE) region, specifically the Poseidon MTS which consistently records the highest levels of curtailment (above 70%), have strengthening initiatives which include the establishment of Poseidon North and South to provide the much-needed relief in the region. The planning and implementation of such transmission expansion initiatives fall under the TDP, which should be consulted for any detailed information.

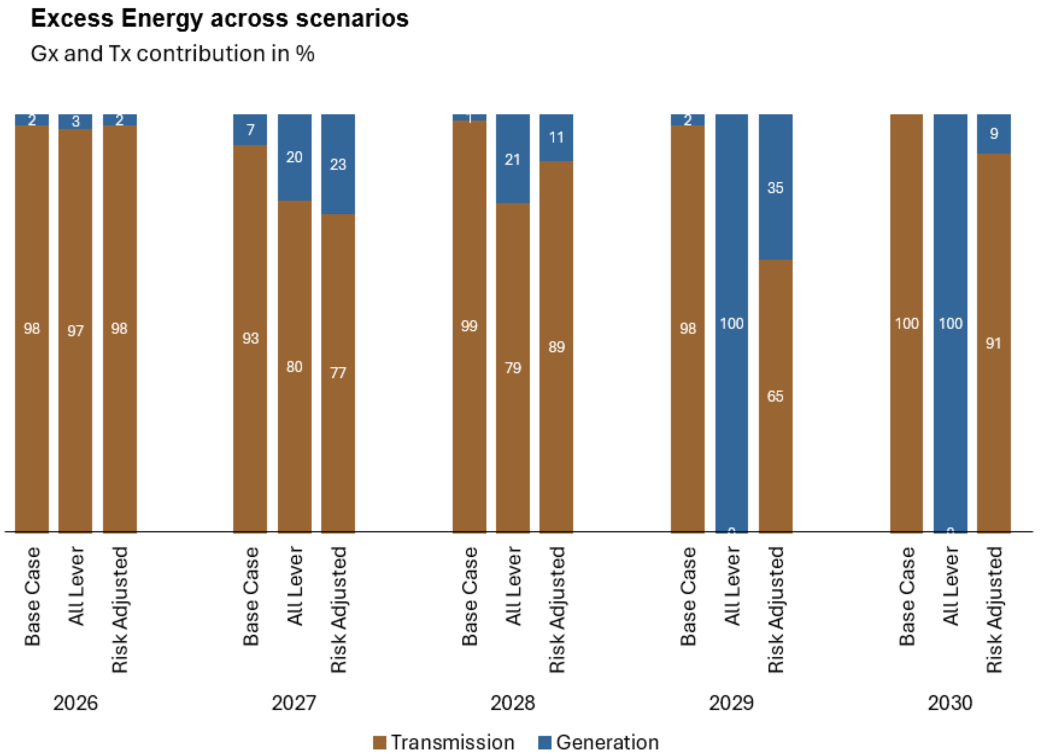

Figure 23: Excess Energy contributions between Generation and Transmission

7.3.3 Worst Excess Energy Scenario

The monthly excess energy analysis for the scenario with the worst excess energy (accelerated build scenario in 2028) is shown in Table 4 below.

Table 4: Monthly excess energy

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	1.07	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.76	0.80	2.66
8	6.47	2.23	0.58	1.60	0.24	0.00	0.02	2.07	7.80	7.80	8.00	13.27
9	25.60	11.70	8.09	18.53	11.36	0.16	1.91	20.71	38.67	34.40	34.64	31.28
10	65.03	37.79	38.93	65.42	58.36	10.61	27.80	86.30	89.92	77.19	70.15	66.36
11	95.13	59.46	62.53	101.80	96.46	34.26	62.32	138.05	125.65	110.18	100.28	90.12
12	115.77	74.88	76.51	109.74	103.84	43.07	79.59	156.87	132.58	121.99	104.45	91.79
13	111.14	73.83	66.33	84.68	73.01	21.34	56.17	130.54	119.58	108.36	92.16	95.53
14	106.22	58.77	45.96	46.40	15.46	0.56	10.17	62.95	73.28	75.32	61.55	83.59
15	70.70	35.24	24.38	10.88	0.00	0.00	0.00	5.79	10.64	26.34	30.48	59.04
16	27.90	4.67	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.27	19.40
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Excess energy predominantly occurs during midday periods, aligning with peak solar PV generation. The largest surpluses are observed during the summer months, primarily driven by strong solar output during this period. These results highlight the growing influence of solar generation on power system operations and underscore the need for enhanced flexibility measures, which include but are not limited to increased BESS integration and demand shifting to absorb surplus generation during the day effectively.

7.3.4 High Excess Energy Week

The week with the highest excess energy from the accelerated build scenario in 2028 is shown in Figure 24 below.

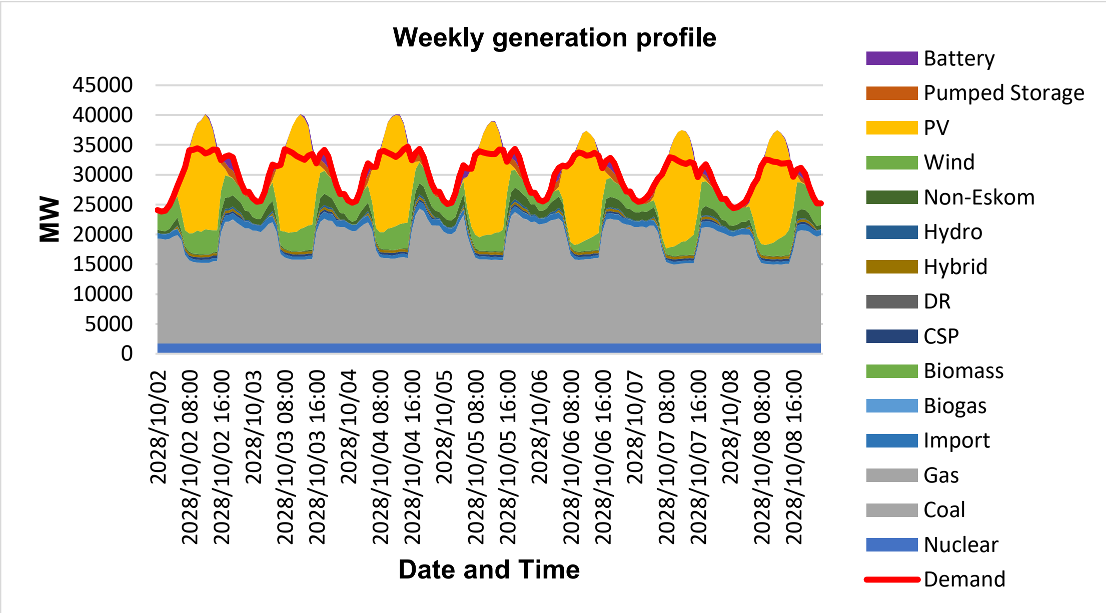

Figure 24: Excess energy weekly profile.

Excess energy during the day relative to demand is expected to fluctuate between 0.2 and 7 GW during excess energy hours, with an average of 3.5 GW over the week analysed. The excess energy is evident even where the system reports unserved energy. This is because excess energy is experienced predominantly during high solar generation hours, while unserved energy occurs in the evenings, when the customer demand is higher and solar generation is lower. A typical day where both unserved energy and excess energy are evident is shown in Figure 25 below.

The coexistence of both unserved energy and excess energy as opposing system issues highlights the power system's structural inflexibility, as available renewable generation cannot be shifted to support the evening peak demand without adequate storage systems.

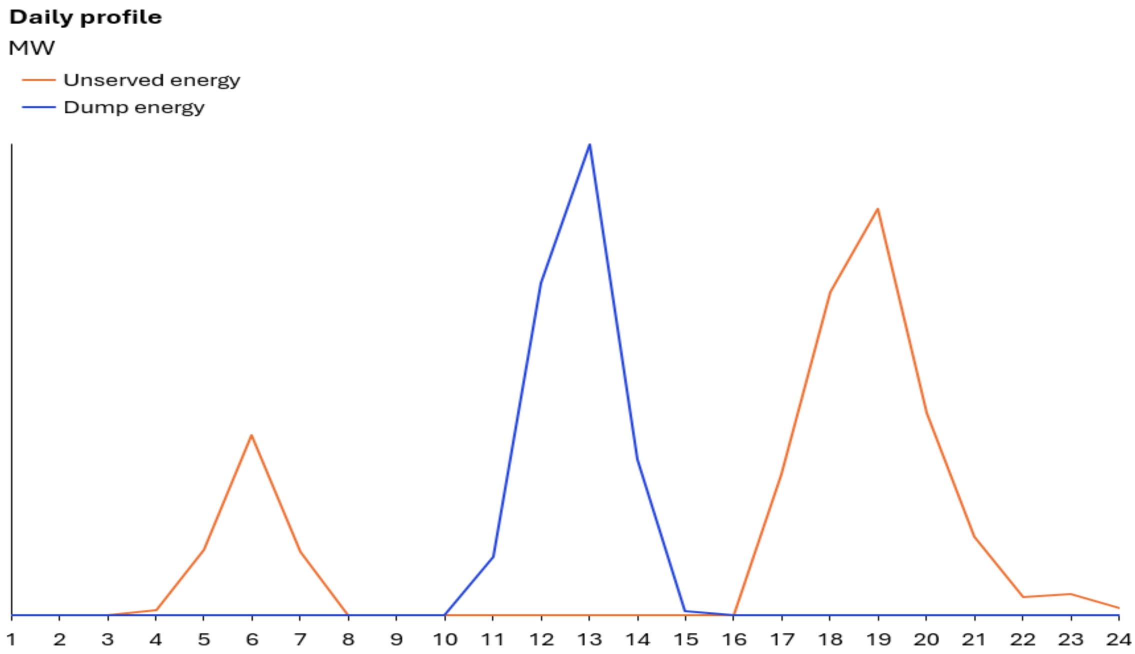

Figure 25: Daily profile.

Furthermore, coal generation plants operate at minimum generation levels when these high levels of excess energy are experienced and will be required to ramp up when the solar generation drops to cater for the evening peak. This is anticipated to happen almost on daily basis and is expected to exert operational strain on coal power plants. Over time, the frequent ramping up and down due to fluctuations in variable generation output is expected lead to accelerated wear and tear on the equipment, potentially resulting in increased maintenance requirements, reduced lifespan and increased maintenance and operational costs. Similar impacts have been highlighted in studies such as Impram et al. (2020), which examined the implications of renewable energy penetration on power system flexibility.

7.4 Sensitivity Analysis

7.4.1 High EAF

7.4.1.1 High EAF - Low Demand Sensitivity

The draft IRP 2024 base EAF showed an improvement to 68% by 2030, which is aligned to the MTSAO 2025 high EAF. Should these higher EAF levels be achieved, the availability of the Eskom fleet will exceed the moderate EAF levels assessed in this study. While this improvement will strengthen the system reliability and security, reduce the risk of unserved energy, and create an opportunity for high economic growth aspirations to be realised, higher EAF is expected to increase the levels of excess energy on the system. The situation is expected to be exacerbated if demand growth falls below the moderate scenario. Studies conducted showed that a high EAF (67%) and a lower demand projection (0.6% AGR) could result in excess energy levels increasing by 91%-98% over the study period relative to the base case scenario.

7.4.1.2 High EAF and gas delay sensitivities

Sensitivity analysis was also conducted on the high EAF, coupled with moderate demand and accelerated new build capacity to assess the impact of a higher EAF if all the new capacity considered in the study materialises. The results showed that a higher EAF coupled with moderate demand and accelerated build capacity results in no unserved energy being reported throughout the study period. However, increased levels of excess energy are evident, and the results are shown in Figure 26 below.

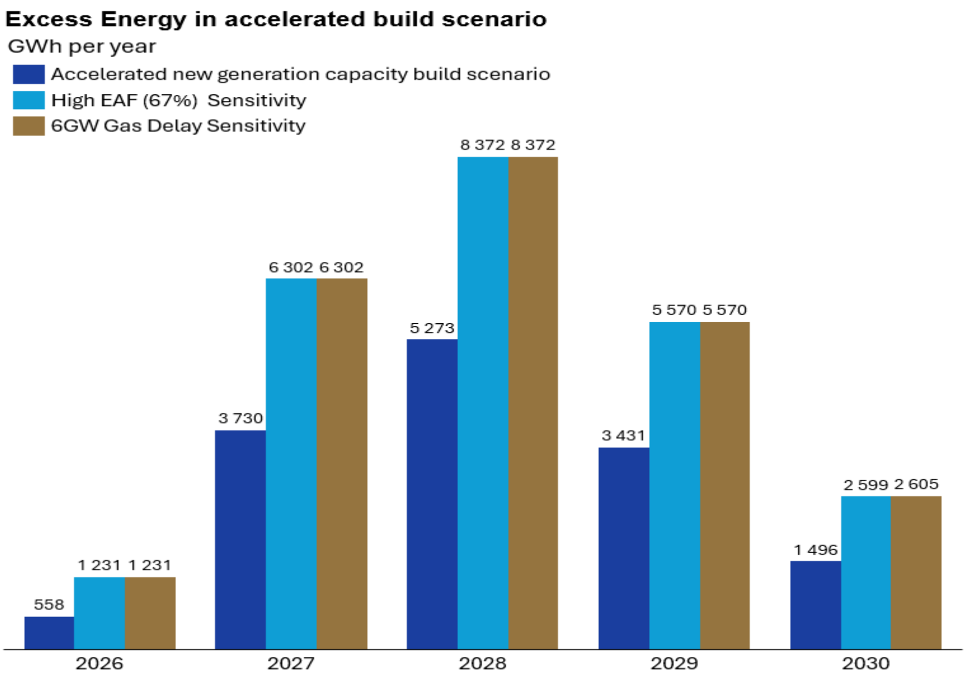

Figure 26: Annual excess energy for accelerated build sensitivities.

Another variation of this analysis was conducted, where 6 GW CCGT capacity is delayed beyond 2030 to assess if high EAF, coupled with moderate demand and all new capacity considered in the study can close the energy gap caused by CCGT delays, as observed with the risk-adjusted scenario. Results showed that unserved energy of 86 GWh is anticipated in 2030 if the 6 GW CCGT capacity is delayed, however, this unserved energy is within manageable levels. In addition, the delay of 6 GW CCGT capacity beyond the study period has no significant impact on the excess energy, indicating that CCGT capacity is not a contributor to excess energy in 2030.

7.4.2 Low EAF and High Demand Sensitivities

The impact of a high demand growth (2.3% AGR) was assessed on committed capacity with the moderate EAF. Results showed no concern for 2026 and 2027, and increased levels of unserved energy and high OCGT utilisation were observed from 2028. The observation indicates that a higher demand growth will need to be supported by improved EAF and/or additional capacity beyond committed capacity.

The study has also assessed the impact of a lower EAF (55% average) on moderate demand and committed capacity. Results showed that the system will continuously experience high unserved energy and high utilisation of OCGTs throughout the study period. This observation indicates that if EAF levels fall below the moderate projection, the security of supply will be at risk.

7.5 Impact of excess energy on grid stability

7.5.1 Excess energy statistics

The System Operator has already begun recording a significantly increasing levels of excess energy. During the 2024 calendar year, approximately 307 GWh of excess capacity was recorded by the System Operator, and this was mostly done to manage system high frequencies, which are experienced when generation far exceeds the demand. In 2025, this trend has intensified, with September 2025 year-to-date excess energy already at 403 GWh.

While the improvements in system performance and additional capacity are welcomed and mark a positive milestone towards fleet recovery and system security, they also underscore the growing operational challenge of managing excess generation within the existing demand, reinforcing the need for strategic implementation of grid flexibility measures. The monthly excess values for 2024 and 2025 are shown in Figure 27 below.

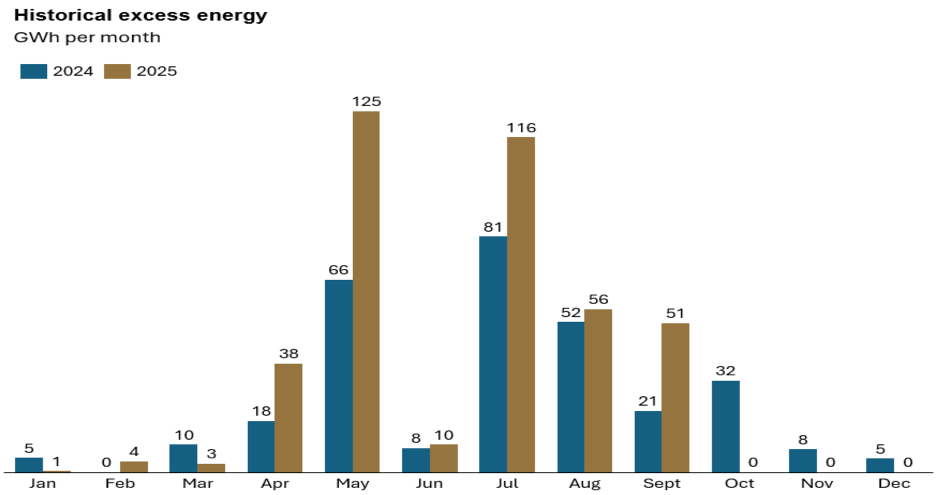

Figure 27: 2024 and 2025 monthly excess energy.

7.5.2 Frequency statistics

The system experienced increased levels of frequency incidents due to increased generator trips and frequent switching actions during load shedding taking place across various network levels to maintain supply and demand balancing. Although the frequency and severity of load shedding events have since reduced significantly, the system continues to record a notable number of frequency deviations outside the operating range of 49.7 Hz to 50.3 Hz. These deviations are attributed to insufficient contracted operating reserves as prescribed by the Ancillary Services technical requirements. Operating reserves have been insufficient due to heavy reliance on older conventional generation, which has been recently experiencing reliability challenges. SO has since pursued the provision of reserves from other technologies e.g. inverter-based plants. The frequency incidents in the calendar years 2024 and 2025 year to date are shown in Figure 28 and 29.

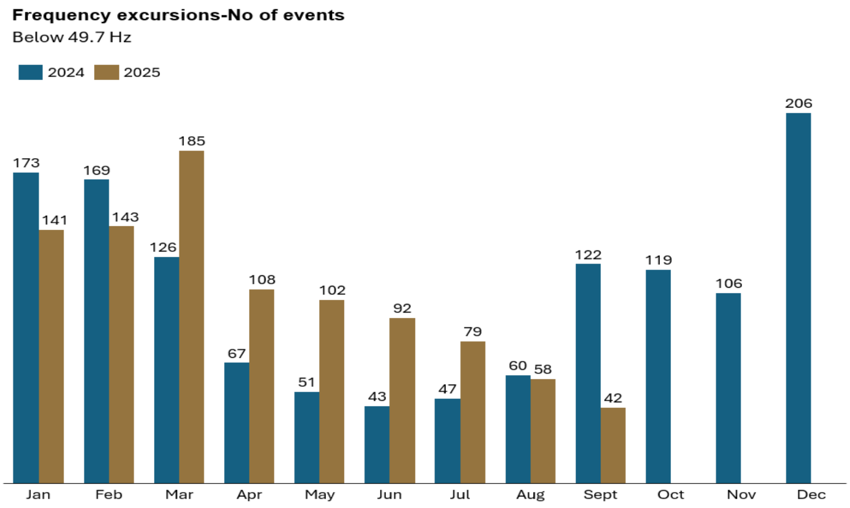

Figure 28: 2024 and 2025 Monthly Low Frequency Events

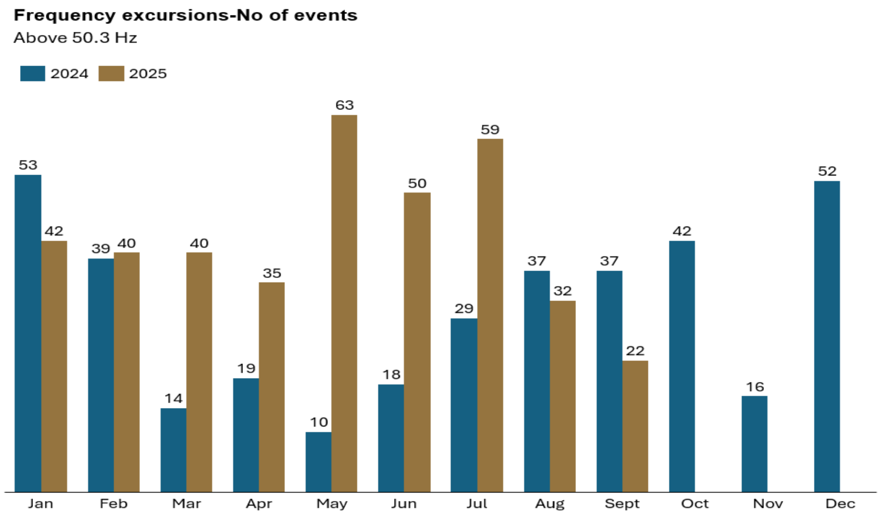

Figure 29: 2024 and 2025 Monthly High Frequency Events

The limited flexibility to meet demand and maintain scheduled frequency on the current power system, as well as increasing levels of PV generation (utility scale and behind-the-meter), are also the contributing factors to high frequency incidents. Limited power system flexibility and high PV generation not only result in increased high frequency events but also increase the duration trends. Consequently, frequency remains outside the defined dead-band for longer periods which exposes the interconnected power system to operational risks e.g. tripping generators due to excessively high frequency and interruption of inter-regional power trade.

Increased levels in low frequency incidents, high frequency incidents and duration trends are evident in the 2025 year-to-date numbers compared to the 2024 calendar year. Figure 30 below indicates that the duration of frequency events is increasing.

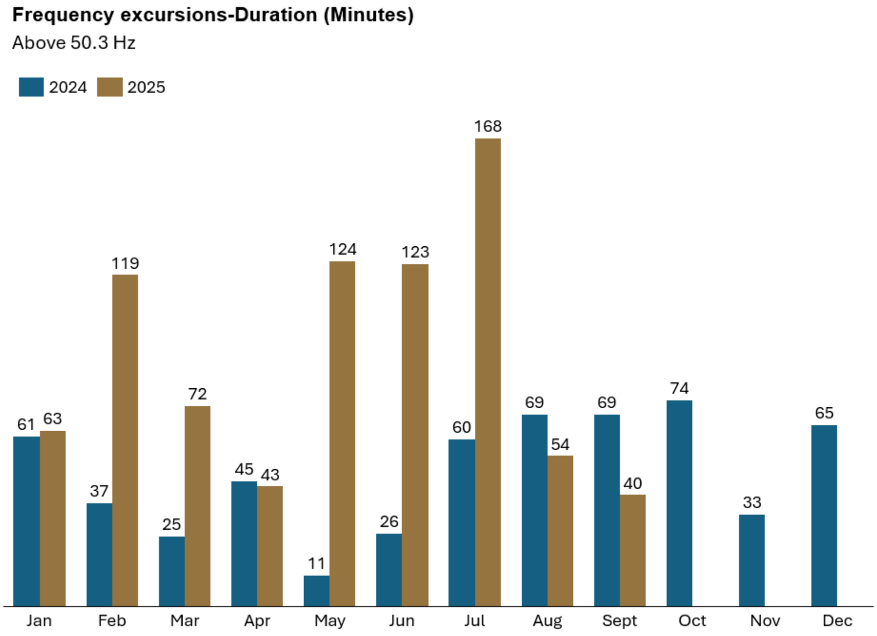

Figure 30: High frequency duration trends for 2024 and 2025

8. OBSERVATIONS

The previous MTSAO studies indicated that improving EAF is the most effective lever to improving the system adequacy in the short to medium term. This has been demonstrated in the previous and current years of reduced load shedding due to improved generation performance. The MTSAO 2025 used a moderately optimistic EAF with an average of 60%, and the system remains adequate at this level of EAF.

The sensitivity done on the low EAF emphasises the importance of maintaining good plant performance as the reduction in EAF to levels below 60% will take the country back to the constrained system and possible load shedding.

The period from 2029 to March 2030 will see a significant Eskom plant shutdown and the end of the supply contract from Cahora Bassa, reducing baseload capacity by 9.5 GW. This is a significant reduction in the system's baseload capacity, which will require measures to mitigate potential inadequacy.

The study assumed that the 6 GW gas to power capacity will become commercial in 2030. This capacity is however at risk of being delayed post 2030. The scenario and sensitivity analysis done on gas delays indicates that this will result in unserved energy in 2030.

The increasing penetration of solar PV, both utility scale and small scale embedded solar, results in high levels of excess energy. This is even more pronounced in the accelerated build scenario, where penetration of renewable energy technologies is high, and this capacity is commissioned earlier than in other scenarios.

The coincidence of both the unserved energy and excess energy occurring on the same day is observed. The unserved occurs during morning and evening peak demand periods, whereas excess energy is primarily observed during daytime hours, coinciding with peak solar PV generation. The integration of increasing solar PV systems necessitates that coal stations produce at minimum generation levels during the day and ramp up during the evening peak, and this is a typical of a system that has a suboptimal generation mix.

9. RISKS TO THE POWER SYSTEM

- The deterioration of system EAF to levels below 60% will pose a risk in the immediate term.
- The potential delay of 6 GW CCGT post 2030 will be exacerbated by the shutdown of Eskom coal fleet (8.4 GW) and the end of the Cahora Bassa contract (1.15 GW) all happening by March 2030.
- Improving the EAF is potentially the lever that could arrest the cliff in the baseload capacity. However, the current MES exemptions at Kendal, Lethabo, Majuba, Matimba, Medupi and Tutuka are applicable until March 2030, thereby placing approximately over 22 GW of baseload capacity at risk of shutdown or reduced output.
- The suboptimal generation mix, which is predominantly solar PV, contributes to increased levels of excess energy, forcing baseload generation to operate at minimum levels and increase over frequency incidents.
- Frequent ramping up and down of Eskom owned coal fleet, will potentially result in accelerated wear and tear on the equipment, increased maintenance requirements, reduced lifespan and increased maintenance and operational costs.
- Increased frequency incidents outside the acceptable operating range for an extended period, caused by limited operating reserves and increased solar PV penetration, expose the interconnected power system to operational risks such as unintended generator trips and interruption of inter-regional power trades.
- The transmission constraints contribution to unserved energy, excess energy, and increased utilisation of OCGTs, will amplify operational challenges and further lead to inefficient use of generation resources.

10. RECOMMENDATIONS

Based on the observations of the study, the study recommends the following:

- Maintain the EAF levels at 60% and above. The Eskom plant reliability improvement initiatives aim to improve EAF to 70% by the financial year 2028, and this will also create an opportunity for high economic growth aspirations to be realised.
- 2030 will see the baseload cliff due to the shutdown of coal fleet and HCB capacity, which will potentially be worsened by the delay in the 6GW CCGT and the risk of MES compliance. A solution for this period and beyond needs to be explored. The delay in the CCGT plant needs to be avoided.
- Integration of utility scale solar PV systems must be coupled with appropriate storage to prevent excessive excess energy on the system. This will maximise renewable energy utilisation, prevent energy wastage, and protect coal-fired power plants from operational stresses.
- Procurement of new generation must be aligned with power system requirements as determined by the IRP. Misalignment with the IRP could lead to a suboptimal generation mix for the system, as observed in the all-lever and accelerated build scenarios.
- Future generation investments should prioritise flexible generation technologies capable of load following and rapid ramping to strengthen system resilience against uncertainties in supply and demand. However, such technologies should be procured in line with the IRP’s determinations to avoid perpetuating the system inefficiencies currently being experienced.
- Although transmission limitations do not pose a significant risk to overall system adequacy, the timely completion of strengthening projects is critical to ensure that new generation can be reliably integrated into key load centres. This will prevent the transmission grid from becoming a contributing factor to unserved energy, excess energy, and increased utilisation of OCGTs.

11. APPENDIX A: SYSTEM OPERATOR STATISTICS

This section monitors and reports actual system reliability indices that are affected by the adequacy of a power system. The data reports trends from January 2017 to 2025 year to date as of the end of September 2025, with data available for retrieval from the National Transmission Company of South Africa Data Portal (2025).

11.1 OCGT utilisation

The System Operator's dispatchable gas peaking plants include Eskom's Ankerlig (1327MW) and Guorikwa (740MW), as well as DOEE OCGTs at Dedisa (335MW) and Avon (670MW). Figure 31 illustrates the generation output from these resources over the past years. Usage of OCGTs to balance supply and demand has increased significantly between 2019 and 2023. However, the utilisation for 2024 reduced considerably compared to 2023, and the year-to-date utilisation is almost the same as the 2024 usage during the same time and is unlikely to increase substantially in the remaining three months of 2025.

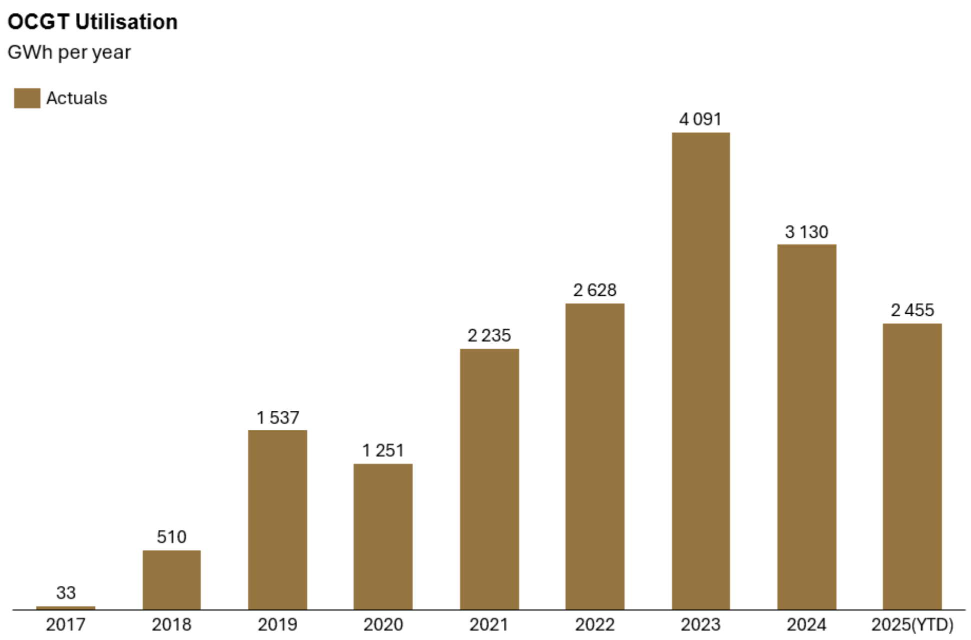

Figure 31: Actual OCGT utilisation 2017 to 2025 YTD

11.2 Unserved Energy

To maintain a stable power system amidst supply shortages, the System Operator implements load shedding and/or demand curtailment. Figure 32 shows historical recorded energy not supplied as 390 GWh for the current year to date. The values include load shedding and load curtailment but exclude interruption of supply (IOS). IOS refers to all contracted and mandatory demand reductions to maintain system frequency and security of supply within acceptable bands.

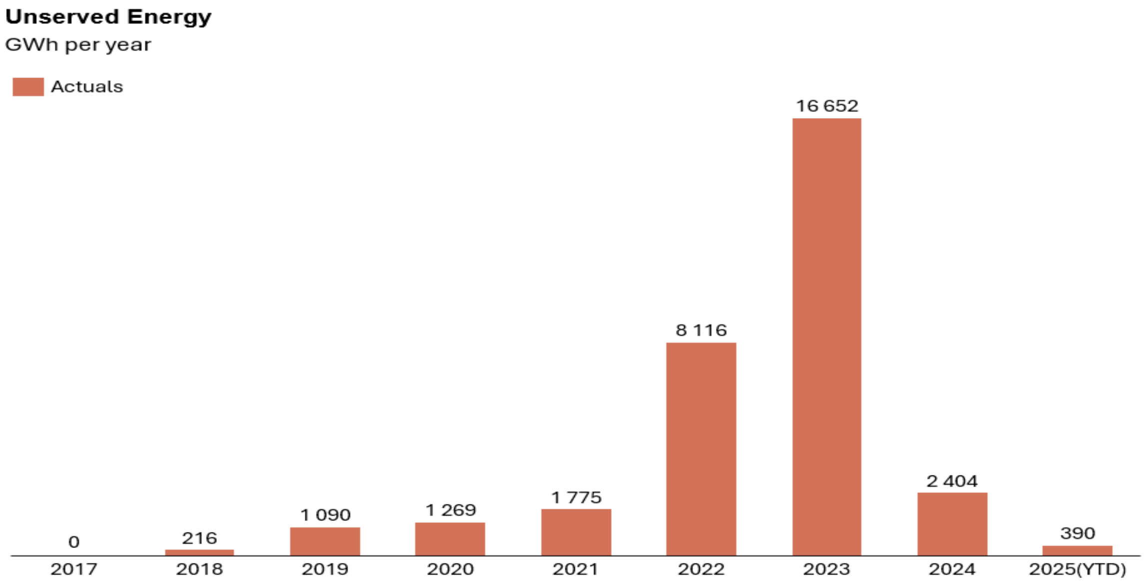

Figure 32: System Operator instructed load shedding for the calendar year 2017 to 2025 YTD

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