ESKOM HOLDINGS SOC LTD

Regulatory Clearing Account (RCA)

MYPD 5: FY2025

Submission to NERSA

March 2026

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1 Preface

This document summarises information submitted by Eskom Holdings (SOC) Ltd to the National Energy Regulator of South Africa (NERSA) pertaining to Eskom's Regulatory Clearing Account (RCA) balance for FY2025 in accordance with the Multi-Year Price Determination Methodology published during October 2016.

1.1 The basis of submission

The basis of this submission is derived primarily from section 17 of the *MYPD Methodology* which provides for a Risk Management Device (Section 17.1) administered by way of the RCA (Section 17.2) as follows:

17.1.1	The risk of excess or inadequate returns is managed in terms of the RCA. The RCA is an account in which all potential adjustments to Eskom's allowed revenue that has been approved by the Energy Regulator is accumulated and is managed as follows:
17.1.1.1	The nominal estimates of the regulated entity will be managed by adjusting for changes in the inflation rate.
17.1.1.2	Allowing the pass-through of prudently incurred primary energy costs as per Section 12 of the Methodology.
17.1.1.3	Adjusting capital expenditure forecasts for cost and timing variances as per Section 17.2.6 of the Methodology.
17.1.1.4	Adjusting for prudently incurred over or under-expenditure on operating costs as may be determined by the Energy Regulator.
17.1.1.5	Adjusting for other costs and revenue variances where the variance of total actual revenue differs from the total allowed revenue (Includes but not limited to taxes and levies (as defined), sales volumes and customer number variances).
17.2.2	The adjustments to be included in the RCA and balance of the RCA will be approved by the Energy Regulator in terms of the MYPD Methodology.
17.2.3	The Energy Regulator will then review Eskom's submission and make a preliminary assessment of any adjustments required in the subsequent financial year's tariffs.

The RCA is part of the overall *MYPD Methodology*, where Section 17.1 confirms that the **RCA is intended to mitigate and manage the risk of excess or inadequate returns, and further that it does so by adjusting regulated revenue.** Section 17 further sets out that the costs and cost variances (to be recovered through such revenue adjustment) will be assessed for prudency.

Disclaimer:

Casting of Tables: *Please note that individual line items in the tables have been rounded to the nearest million rand. As a result, some subtotals may not "cast" exactly when added by eye. However, the published totals accurately reflect the full, unrounded underlying values.*

2 Executive Summary

2.1 Context of the NERSA FY2025 revenue decision

The revenue application for FY2025 was prepared in accordance with MYPD methodology as published by the National Energy Regulator of South Africa (NERSA) during October 2016. The Energy Regulator's allowable revenue decision for FY2025 was R352 168m for all customers (inclusive of previous RCA liquidations). The standard tariff allowable revenue for FY2025 was R336 057m resulting in an effective average standard tariff increase of 12.74%, which was implemented in the schedule of tariffs from 1 April 2024. FY2025 is the third and final year of the MYPD5 period. The NERSA revenue decision was announced on 14 December 2022. The reasons for decision were published on 12 January 2023. As is evident in the NERSA revenue decision, Eskom is still in the process of migrating towards a cost reflective tariff. The return on assets (ROA) that NERSA allowed in its decision was 1.58%. The gap between the granted ROA and the NERSA determined weighted average cost of capital of approximately 10% still needs to be addressed.

The 2025 financial year marked a pivotal year for Eskom and the South African electricity supply industry. NERSA approved a standard tariff increase of 12.74% for FY2025. This increase was intended to support Eskom's financial sustainability while balancing affordability for customers and the broader economic context, which continues to be challenged by slow GDP growth, high unemployment, and persistent inflationary pressures.

This RCA application reflects South Africa's ongoing efforts to balance electricity supply and demand in a challenging environment. In FY2025, Eskom's coal-fired power stations continued to provide the backbone of supply, delivering approximately 80% of total energy. Despite high energy utilisation factor, improved maintenance and operational recovery initiatives enabled Eskom to meet demand with far greater stability than in previous years.

FY2025 saw a significant turnaround in Eskom's operational performance. Loadshedding reduced to just 13 days (from 329 days in FY2024). The Energy Availability Factor (EAF) improved to 60.90% (FY2024: 54.56%), driven by disciplined execution of the Generation Recovery Plan, targeted maintenance, and the return to service of key units such as Medupi Unit 4 and Kusile Units 1–6. Total sales volumes increased from the previous year, supported by improved plant reliability and reduced reliance on open-cycle gas turbines (OCGTs).

Independent power producer (IPP) contributions were below initial expectations, with actual IPP energy supplied at around 19.4 TWh, which corresponded to shortfall of over 17 TWh when compared to the NERSA decision. This shortfall was offset by Eskom's improved plant performance and reduced reliance on emergency generation. The use of start-up fuel remained necessary to support coal plant operations, but the most notable shift was the sharp reduction in OCGT usage: Eskom OCGT production fell to 2 176 GWh (from 3 634 GWh in FY2024), and IPP OCGT production also declined.

The key variances in this RCA application support the significant improvement in operations experienced in this financial year. Eskom's system again had the added burden of filling the gap created by the IPPs not providing energy as NERSA had determined. This invariably puts additional strain on Eskom's operations. It is fortunate for the country that Eskom was successful in meeting the requirements for the majority of the financial year.

2.2 Summary of FY2025 RCA application

The overall RCA variance being applied for is R8 858m for the benefit of the consumer. The necessity of the RCA mechanism that allows for adjustment based on actuals is demonstrated by this balance in favour of the consumer. The FY2025 RCA submission is driven substantially by various cost variances – either for the benefit of the consumer or the benefit of Eskom. The key variances for the benefit of the consumer are for IPPs, international purchases and depreciation. The key variances for the benefit of Eskom are for operating costs and primary energy. The shortfall in energy secured from IPPs required the utilisation of additional primary energy components to contribute to meeting the majority of the demand. Having to secure availability of plant and supply of electricity to end customer required further operating costs – mainly employee benefit and maintenance costs.

TABLE 1: SUMMARY OF FY2025 RCA APPLICATION (RM)

RCA for FY2025	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Regulated Assets Base (RAB)	988 345	1 086 524	98 180	-	97 739
Return on Assets (ROA)	1.58%	1.58%			-
Return	15 616	17 167	1 551	-	1 551
Expenditure	60 971	109 911	48 940	(26 813)	22 127
Primary Energy	92 817	90 738	(2 079)	8 741	6 662
Independent Power Producers (local)	76 970	47 273	(29 697)	-	(29 697)
International purchases	9 334	6 540	(2 794)	-	(2 794)
Depreciation	73 376	67 257	(6 119)	-	(6 119)
IDM	473	170	(304)	-	(304)
Levies & taxes	6 503	7 270	767	-	767
Carbon Tax	-	3	3	-	3
Total revenue from all customers after RCA's	352 168	353 223	(1 056)	-	(1 056)
Service quality incentive (SQI)	-	-	-	-	-
FY2025 RCA balance due to Eskom/(Customers) applied for					**(8 858)**

Notes:
1. IDM included in Operating costs (Opex)
2. IDM in the table above refers to Power Alerts, Demand Response and Dx International Purchases
3. Costs variance is calculated as Actual minus Decision
4. Revenue variance is calculated as Decision minus Actual

2.3 Legal and regulatory framework for RCA Application

The adherence to relevant legislative, regulatory and licence requirements, court judgements and orders form the basis of the RCA submission. These include the Electricity Pricing Policy, Electricity Regulation Act, MYPD methodology, South African Grid and Distribution Codes and Guideline on Prudency Assessment. Eskom has also based this application on precedents set in the previous RCA decisions and in compliance with court orders.

2.4 Revenue variance

The MYPD methodology requires the recovery of the total variance in revenue where certain adjustments are made to the revenue reflected in Eskom's annual financial statements. A revenue variance of R1 056m for the benefit of the consumer is included in the RCA balance. This is mainly due to loadshedding sales volume not being included in the RCA balance.

Adjustments include ensuring all billed revenue is considered, revenue from non-electricity sources is excluded and loadshedding revenue variances are specifically excluded. For FY2025, load shed energy was estimated at 354 GWh (a dramatic reduction from 13 215 GWh in FY2024), and the corresponding revenue is excluded from the variance calculation.

2.5 Production Plan

The Production Plan illustrates that the energy sent out was 218.6 TWh which consists of 195.7 TWh from Eskom Generation, 19.4 TWh from IPPs, 9.6 TWh from international imports and subtracting pumping requirements of about 6.1 TWh.

Actual production closely aligned with the plan, supported by a marked improvement in plant performance and reduced reliance on emergency generation. The EAF for the Eskom generation fleet improved to 60.9% (FY2024: 54.6%), underpinned by enhanced maintenance, reduced forced outages, and improved reliability at key baseload stations.

Coal-fired generation remained the backbone of Eskom's supply portfolio, contributing around 80% of total energy sent out. Improved unit reliability enabled sustained operation without the extreme stress conditions observed in the prior year. The coal EUF 92% (FY2024: 96.5%), still indicating an abnormally high operating regime relative to international benchmarks. This high utilisation is not sustainable and results in accelerated wear and tear necessitating more frequent maintenance intervals.

The marked improvement in availability meant Eskom relied far less on OCGTs for peaking and emergency generation. Eskom OCGT production declined to 2 176 GWh (FY2024: 3 634 GWh) and IPP OCGT production declined to 662 GWh (FY2024: 1 509 GWh) as system stability improved.

The combination of higher EAF, lower unplanned losses, and reduced dependence on OCGTs enabled Eskom to deliver one of its most stable operational years in recent history. Loadshedding was reduced from 329 days in FY2024 to just 13 days in FY2025, while overall energy sent out increased relative to the previous year. Improved coordination with IPPs, greater hydropower and renewable integration, and more efficient scheduling of pumped-storage operations further supported supply reliability.

FY2025 marked a substantial operational turnaround for Eskom's generation fleet. Enhanced maintenance planning and execution under the Generation Operational Recovery Plan, together with improved fleet reliability and efficiency, allowed Eskom to meet system demand with minimal loadshedding and significantly lower OCGT usage.

2.6 Primary energy variances

The overall variance for primary energy is R25bn for the benefit of the consumer. Variances are either in favour of the consumer or Eskom. The variances in favour of the consumer include R29.7bn for IPPs, R2.8bn for international purchases and R1bn for OCGT. These are offset by variances in the favour of Eskom that include mainly coal cost variances of R4.3bn and start-up fuel variance of R3.4bn. These variances indicate the nature of dependence mainly on Eskom primary energy to ensure the operation of the system.

Over 17 TWh that was to be secured from IPPs did not materialise as assumed by NERSA in its decision for FY2025. Thus, only approximately 19 TWh of energy was secured from IPPs. The average costs for IPPs were higher at R2 441/MWh against the decision of R2 085/MWh. This resulted in a variance of approximately R29.7bn for the benefit of the consumer.

The total coal cost variance is R4.3bn in favour of Eskom. A coal burn price variance of R5.1bn for the benefit of the consumer and a coal burn volume variance of R10bn contribute to an overall coal cost variance of R4.9bn for the benefit of Eskom. The variance of R4.3bn is capped at the difference between the actuals and decision. This indicates that coal was secured at a lower average price than determined by NERSA and volumes of coal utilised was more than that determined by NERSA. This is due to Eskom Coal Generation having to supplement the lower than the NERSA decision anticipated IPP supply.

Start-up fuel variances contribute R3.4bn in favour of Eskom to the RCA balance. Eskom reduced startup fuel oil expenditure from R8.7bn in FY2024 to R7.5bn in FY2025. This improvement reflects fewer plant restarts and more stable operational patterns under the Generation Operational Recovery Plan. There were fewer cold and warm start-up events which require extensive oil firing.

The successful implementation of the Generation Operational Recovery Plan required lower OCGT dependence where energy sent out for FY2025 was 2.2 TWh (3.6 TWh in FY2024). The consumer also benefited from Eskom reaching a settlement of a dispute on refund of rebates with the South African Revenue Services (SARS). The overall OCGT cost variance is R1bn is in favour of the consumer.

2.7 Regulatory Asset Base (RAB) Adjustments

At the decision phase for FY2025, NERSA has implemented some aspects of the 24 October 2022 High Court Order on the RAB valuation. However, certain aspects have not been implemented. For the determination of transfer to commercial operation, NERSA had not considered the opening balance by assuming that it is already in the RAB value. This is not the case. A similar incorrect approach to work under construction (WUC) was implemented. Only current WUC (Capital expenditure) had been allowed while historic WUC had been disallowed.

Eskom had maintained the decision RAB value for depreciated replacement of existing RAB. The High Court order related to the correction of the FY2024 RAB value. The order requires the correction of the RAB value, in accordance with the NERSA methodology, in subsequent decisions by NERSA. The variances in the return on assets were determined to be R1 551m in favour of Eskom and depreciation of R6 119m in favour of the consumer. A variance in the commissioning of Eskom's Generation, Transmission and Distribution capital projects was observed. There was a misalignment between NERSA's decision on assets transferred to commercial operation and depreciation.

2.8 Operating expenditure variances

The overall operating costs variance, of R22bn is in favour of Eskom. The key reason for this variance is the need to make investments in operating expenditure to continue to improve Eskom's operations. This comes with additional, yet viable costs. Operating expenditure is actively managed to ensure that it is at prudent and efficient levels. As part of this management process, costs are benchmarked against international norms. Eskom strives to operate within international benchmarked norms unless there is strategic intent to further increase maintenance to improve technical performance due to ageing plant or higher utilisation compared to international benchmarks.

During FY2025, the relinking to operating divisions continued. This was not anticipated at the time of the application and decision. The increase in employee numbers and associated employee costs within generation and transmission was to address operational stability, skills shortages, and future sustainability in the businesses. The number of employees in the Distribution business decreased when compared to the application. The Eskom Board approved the reimplementation of the short-term incentive scheme for FY2025 to incentivise operational performance excellence and support employee retention. However, these costs were not included in this RCA balance application.

A significant variance is seen in maintenance costs. This investment in maintenance has contributed to improved performance across generation, transmission and distribution. The continued implementation of the Generation Operational Recovery Plan has borne improved results in the generation performance in FY2025. This is evident by a marked decrease in the number of load shedding days as well in the severity of load shedding. The further focus on generation maintenance, as was not envisaged when the decision was made, contributed to the increased maintenance costs. The transmission plant is ageing, which adversely affects system reliability and necessitates sustained and intensified intervention.

Other operating costs include all costs involved in the day-to-day running of the business. The MYPD 5 Revenue decision for FY2024 of R5 863m included a Generation once-off credit adjustment of R4bn and a Distribution translation error of approximately R1bn before the NERSA revenue determination analysis started. This resulted in an artificially low unsustainable other opex decision for Eskom, which does not take into account the abnormal changes. In the FY2023 RCA RfD NERSA corrected the base by taking Eskom's business model into account reflecting the true cost base of the licensees. NERSA considered all elements when it assessed the application for other operating costs before the final determination was made. It is expected that NERSA will apply the same approach in the analysis of the FY2025 RCA applications.

Arrear debts were not catered for in the NERSA decision. Thus, they needed to be excluded and accounts for an adjustment to the actuals.

2.9 Addressing corrupt activity

As guided by NERSA, Eskom continues to make efforts to recover any funds related to corrupt or fraudulent activity and transactions. This is an ongoing process and very dependent on the relevant authorities finalising investigations and legal processes.

The Board has adopted a multi-pronged approach to combatting crime, fraud and corruption, centred on prevention, detection, investigation and corrective action. Preventative efforts have focused on reinforcing ethical behaviour as well as strengthening governance and controls, supported by improved systems and processes. Detection capabilities have been enhanced to allow for more effective monitoring and identification of unlawful behaviour.

2.10 Liquidation of RCA balances

The MYPD methodology requires a liquidation decision to be made in the subsequent year's tariff. Due to the requirement for audited results before submission of the RCA application, there would be a natural delay of at least one year. There are a myriad of previous RCA balance decisions, dating back from FY2015 that still need to be liquidated. It is proposed that the level of RCA liquidations be maintained at approximately R23bn per year. This will ensure no impact due to liquidation of RCAs and revenue. The liquidation of balances due to consumers should be proiritised.

2.11 Conclusion

This RCA application is for an amount of approximately R9bn in favour of the consumer. One of the key reasons for this benefit to the consumer, is a combination of the inability of Independent Power Producers to provide the energy as planned and Eskom being in a position to fill the gap of providing the energy. Additional operating costs were essential for the improvement of the overall Eskom operations. This investment in maintenance and employee benefit costs has resulted in reaching a more sustainable operational environment. It is proposed that the RCA balance decisions from 2015 to presently be liquidated in a phased manner to balance the impact on consumers and yet allow for Eskom's sustainability.

3 Legislation and Policy

The adherence to various relevant legislative, regulatory, licence requirements and court judgements form the basis of the RCA submission. The following include those that are applicable to the determination of Eskom's RCA balance and resulting tariff adjustments when the RCA balance is liquidated.

3.1 Electricity Regulation Act (Act No.4 of 2006)

Prescribes tariff principles including:

- Revenues enabling an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return;
- Approval of tariffs by the Energy Regulator

3.2 Electricity Pricing Policy (EPP)

The EPP gives broad guidelines to the Energy Regulator in approving prices and tariffs for the electricity supply industry. Included in the EPP is that electricity tariffs in South Africa should be cost reflective within 5 years as of December 2008. There is also a requirement for NERSA to annually provide a 10-year electricity price path in South Africa.

3.3 Government Support Framework Agreement

The Government Support Framework Agreement (GSFA) with regards to the Department of Energy procured Independent Power Producers, under section 34 of the Electricity Regulation Act. This was signed by Government (represented by the Ministers of Energy, Finance and Public Enterprises) and Eskom in 2012. In accordance with section 3.1.4(e) of the GSFA, Eskom is required to consult with and seek approval from the Department of Energy (DOE) together with the Department of Public Enterprises (DPE) and National Treasury with regards to the proposed amounts for IPP purchase costs and payment obligations to be included in any revenue application. Due to the merging of Government Departments, the Departments to be consulted are the National Treasury and Department of Electricity and Energy.

3.4 Multi-Year Price Determination (MYPD) Methodology

The revenue application is based on the requirements of the MYPD methodology as published by NERSA during October 2016. The MYPD methodology addresses two broad aspects, namely, the MYPD allowed revenue application and the adjustment of the allowed revenue through the regulatory clearing account (RCA) process. **The focus of this application is the MYPD RCA adjustments for the 2025 financial year**.

The key aspect of the MYPD methodology that will be applied in this RCA submission will consider the two step RCA process:

a. The **decision** on the **RCA balance** that is due to Eskom or the consumer, and
b. The RCA balance decision will then be subject to an **implementation decision** (liquidation) guiding subsequent adjustments in tariffs.

In summary, the RCA mechanism allows Eskom the opportunity to achieve the initial revenue that was allowed during the revenue decision and to increase/decrease the allowed revenue due to changes in assumptions or costs that are subject to re-measurement as outlined in the MYPD Methodology. Additional revenue is not being recovered.

3.5 NERSA Guidelines for Prudency assessment

NERSA issued guidelines for prudency assessment during August 2018. Eskom has based this RCA submission on the principles of this guideline.

3.6 Eskom Retail Tariff and Structural Adjustment (ERTSA) Methodology

The ERTSA is applicable to Eskom's Standard tariffs for local authorities (Municipal) and non-local authorities (non-municipal). Eskom is required to make an ERTSA submission prior to the start of each financial year. The revenue decision applicable for the particular year as well as any RCA liquidation decisions made by NERSA will need to be considered when the ERTSA submission is made.

4 Revenue variance

The objective of this section is to demonstrate and explain the revenue variance between decision and actuals for FY2025.

4.1 MYPD Methodology requirements

The regulatory clearing account (RCA) balance is calculated by determining the variances which arise by comparing the FY2025 revenue decision to the Eskom actuals for particular revenues and costs as provided for in the Methodology. The calculation of the revenue variance to be included in the RCA is in terms of paragraph 17.1.1.5 of the MYPD Methodology as shown below.

> 17.1.1.5 Adjusting for other costs [7] and <u>revenue variances where the variance of total actual revenue differs from the total allowed revenue</u>.
>
> Footnote 7 as above: Includes but not limited to taxes and levies (as defined), sales volumes and customer number variances.

Eskom has always complied with the MYPD methodology in determining the revenue variance for the RCA balance.

4.2 Revenue variance calculation

When computing the RCA balance, it is important to compare the same reference points. The table below shows the items that need to be excluded from Eskom Company revenue in order to calculate revenue variance for RCA purposes.

TABLE 2: CALCULATION OF THE REVENUE VARIANCE (RM)

Revenue	(Rm)
Allowable Revenue for FY2025	**352 168**
Less: Revenue for the RCA purposes for FY2025	**353 223**
Actual Revenue for Regulatory purposes	354 095
RCA Adjustments	(871)
Non electricity revenue	*(1 565)*
Load shedding	*694*
Revenue variance	**(1 056)**

4.2.1 Actual Revenue for RCA purposes

To arrive at the actual revenue the following adjustments are made:

4.2.1.1 Reversal of IFRS 15 adjustment

In terms of IFRS 15, a portion of the electricity revenue is not recognised as revenue, since it is assessed that there is a high probability that the economic benefit will not materialise (i.e. high probability that not all revenue billed will be collected). However, in terms of the MYPD methodology this revenue is added back since the sale of energy took place. Thus, the RCA includes all billed revenue, as opposed to collected revenue. Thus, Eskom's challenges with recovering all billed revenue are not a burden on consumers.

4.2.1.2 Basis for adjustment for Eskom electricity costs

In terms of IFRS, Eskom internal electricity costs are shown in revenue. However, for regulatory purposes, when computing the RCA revenue variance all electricity revenue whether it's internal or external is shown in the RCA actual revenue. The Eskom internal electricity costs are therefore reallocated to operating costs.

4.2.1.3 Basis for demand response reallocation to primary energy

Costs associated with payments made for demand response are included in the revenue in the Annual Financial Statements (AFS). This is a requirement in terms of the accounting standards. For the purposes of the RCA balance application, it is necessary to reallocate the costs associated with demand response from revenue to primary energy costs.

4.2.1.4 Basis for excluding non-electricity revenue

In terms of IFRS, non-electricity revenue (i.e. money received in advance from customers as a contribution to asset creation) is included in revenue. In contrast to IFRS, paragraph 9.1.5 of the methodology states that *"The RAB should exclude any capital contributions by customers. Allowance will be made for electrification assets to allow for future replacement of such assets at the end of their economic life".* Non-electricity revenue is removed from electricity revenue (not taken into account when calculating the revenue variance) and credited to capital expenditure (this will reduce transfers to commercial operation).

4.2.1.5 Load reduction adjustment

During FY2025 thirteen days of loadshedding and curtailment incidents were experienced. The total load reduction was determined to be a maximum of 354 GWh. Eskom has not included the volume of energy related to loadshedding or curtailment as part of the sales volume variance.

Eskom has computed the **revenue loss impact using the standard tariff rate.** The load reduction impact of **354 GWh is multiplied by the average standard tariff price of 195.95c/kWh.** This equates to total revenue attributable to the load reductions of **R694m**. The details of the overall trends in loadshedding for the financial year are explained below.

4.2.1.6 Load Shedding and Curtailment

4.2.1.6.1 Summary

TABLE 3: LOADSHEDDING AND CURTAILMENT SUMMARY

Month	Instructed Load Shedding Hours	Instructed Load Curtailment Hours	Total Instructed Load Shedding and/or Curtailment Hours	Days on which Load Shedding and/or Curtailment Occurred	Estimated Load Reduction (GWh)
April 2024					
May 2024					
June 2024					
July 2024					
Aug 2024					
Sep 2024					
Oct 2024					
Nov 2024					
Dec 2024					
Jan 2025	7.0	-	7.0	1	12.3
Feb 2025	113.5	34	113.5	7	245.9
Mar 2025	54.6	22	54.6	5	95.5
Total FY2025	**175**	**55**	**175**	**13**	**354**

Load shedding hours and the load curtailment hours are not mutually exclusive; this means load curtailment occurs mostly during the same time as load shedding. Therefore, the column "Total Instructed Load Shedding and/or Curtailment Hours" is not the sum of the two columns preceding it.

4.2.1.6.2 Load Shedding Overview for FY2025

For the period 1 April 2024 – 31 Mar 2025, a total of 13 days of load shedding and load curtailment occurred. The load reductions were primarily due to the following conditions:

- Shortage of generation from Eskom generators and IPP's.
- Increased unplanned unavailability.
- Limited fuel availability at peaking stations.
- The need to conserve and replenish depleted emergency resources.

There are two key reasons why the System Operator implements loadshedding:

- Inadequate capacity to meet the demand. In winter this is normally only over the evening peaks and in summer this is for up to 24 hours per day

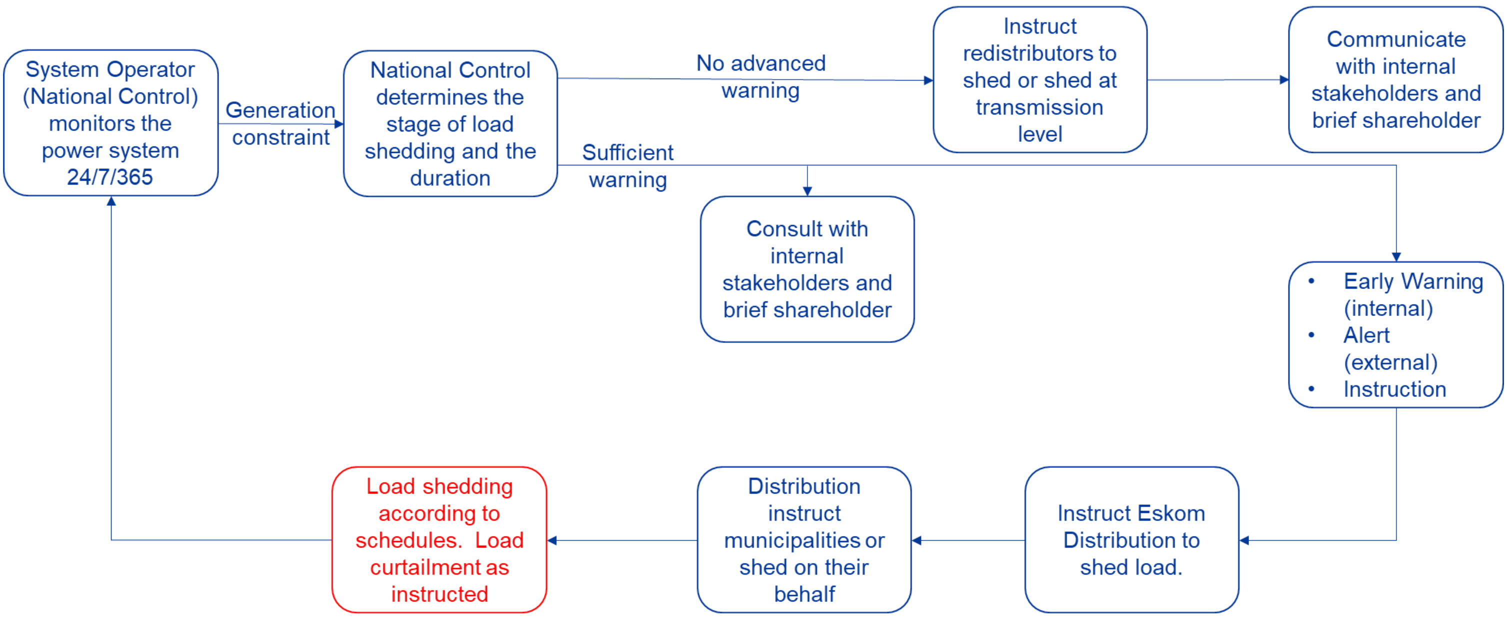
- To enable the restoration of dam levels at Hydro Pump Storage power stations and recovery of OCGT level.

In both cases Load shedding is implemented to restore and retain power system stability and avoid total collapse of the power system.

The South African Grid Code mandates the System Operator to maintain a stable grid including shedding load if necessary. The decision to shed load, especially at an escalated level, is not taken lightly and is always made with operational forethought. With the prevalent unavailability of key base load generation resources, there would not have been sufficient capacity to meet the demand for this period and still maintain a minimal level of reserves for control of the power system in the event of a contingency.

The figure below shows the steps taken by System Operator prior to taking a decision to shed load.

FIGURE 1: LOADSHEDDING DECISION-MAKING



A guiding principle of implementing load reduction in terms of NRS048-9 is that all participants be treated equitably. Equitable participation is a requirement that arises from the Electricity Regulation Act which requires that customers supplied by different licensees must be treated similarly.

4.2.1.6.3 Detailed loadshedding schedules

TABLE 4: DETAILED LOADSHEDDING SCHEDULES

Date	Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding		Stage 5 shedding		Stage 6 shedding		Curtailment stage 1/2		Curtailment stage 3		Curtailment stage 4	
	Start	Stop	Start	Stop	Start	Stop	Start	Stop	Start	Stop	Start	Stop	Start	Stop	Start	Stop	Start	Stop
Fri 31-Jan-2025					17:00	23:59												
Sat 01-Feb-2025					00:00	23:59												
Sun 02-Feb-2025					00:00	06:00												
Sat 22-Feb-2025					17:30	23:59									19:30	23:59		
Sun 23-Feb-2025					00:00	00:38	00:38	01:30			01:30	23:59			00:00	23:59		
Mon 24-Feb-2025							00:30	23:59			00:00	00:30			00:00	05:00		
Tue 25-Feb-2025			05:00	23:59			00:00	05:00										
Wed 26-Feb-2025			00:00	05:00														
Fri 07-Mar-2025					14:00	23:59									15:00	23:59		
Sat 08-Mar-2025					00:00	23:59									00:00	12:54		
Sun 09-Mar-2025					00:00	10:00												
Wed 19-Mar-2025			18:25	23:59														
Thu 20-Mar-2025			00:00	05:00														

a) 31 January – 2 February 2025

Load shedding was implemented for a total of three days, from 31 January to 2 February 2025. Prior to the commencement of load shedding, emergency resources (peaking gas generation and Interruptible Load Shedding (ILS)) resources were dispatched from 27 January to 31 January 2025 in response to deteriorating system conditions. Despite these interventions, the continued strain on the power system ultimately necessitated the implementation of load shedding.

Over this period, unplanned unavailability (UCLF+OCLF) ranged from 13 277 MW to 15 683 MW which was well above the base assumption of 13 000MW for unplanned outages. However, with planned outages, the total average generation unavailability (PCLF + UCLF + OCLF) breached the 22 000 MW with an average value of 20 998 MW from the 27 January - 7 February 2025. Load shedding became unavoidable due to depleted water and diesel reserves.

Stage 3 load shedding was implemented from 31 January to 2 February 2025 to stabilise the system amid increased generation unavailability, higher-than-average demand, and prolonged use of emergency resources that required replenishment. Following a rapid recovery in dam levels, load shedding was suspended on 2 February 2025.

b) 22 February - 26 February 2025

During the latter part of February 2025, load shedding was implemented for five days, from 22 to 26 February 2025. In response to deteriorating system conditions, emergency resources (peaking gas generation and ILS resources) were dispatched from 17 to 28 February 2025. Despite these interventions, the sustained system constraints ultimately necessitated the implementation of load shedding.

Over this period, UCLF+OCLF ranged from 13 052 MW to 17 592 MW which was well above the base assumption of 13 000MW for unplanned outages. However, with planned outages, the total average generation unavailability (PCLF + UCLF+ OCLF) breached the 25 000 MW with an average of 22 102 MW from the 17 - 28 Feb 2025.

Multiple unit trips at Majuba and Camden led to the imposition of load shedding. Stages 3, 4, and 6 load shedding were implemented to stabilise the system amid increased generation unavailability and the prolonged use of emergency resources requiring replenishment. Stage 6 load shedding enabled the recovery of dam and diesel levels. Lower-than-forecast renewable energy generation further exacerbated system constraints. Load shedding was progressively reduced to Stage 2 and fully suspended on Thursday, 27 February.

c) 7 March - 9 March 2025

During the month of March, three days of load shedding took place between 7 to 9 March 2025. Prior to loadshedding implementation, emergency resources (peaking gas and ILS resources) were dispatched from 3 to 10 March 2025 as a response to deteriorating system conditions. Despite these interventions, the sustained system constraints ultimately necessitated the implementation of load shedding.

Emergency reserves were utilised during March to manage the system demand throughout the day due to the lack of generation availability and renewables. The average capacity deficit during the period 3 – 10 March was approximately 1450MW and peaked at approximately 2700 MW.

Generation Units tripped at Kusile, Majuba and Arnot on Friday, 7 March. At the same time, the dam and fuel levels where almost depleted. This led to the decision of stage 3 load shedding being made. Load shedding was required to support the system over the weekend due to increased generation unavailability and extended usage of emergency resources which required replenishing. Load shedding was suspended on Monday 9 March 2025.

4.2.2 Allowed revenue decision

The NERSA allowed revenue decision for all customers in FY2025 was R336 057m (before RCA liquidation adjustments) based on a total sales volume of 191 946 GWh.

4.2.3 Sales Volume Variance Explanations

The FY2025 period was marked by improved system stability following the reduction in load shedding alongside evolving customer consumption patterns. Despite these improvements, total electricity sales volumes were below the NERSA MYPD5 determination, with actual local sales of 175 754 GWh against the decision of 181 359 GWh, resulting in a negative variance of 5 605 GWh. The shortfall was primarily driven by reduced demand from redistributors, prepayment, residential, industrial, and mining customers.

Key contributing factors included municipal load reduction measures, increased adoption of alternative energy sources such as solar and gas, illegal connections and meter tampering, operational challenges in energy-intensive sectors, and economic pressures affecting industrial output. Positive variances were observed in the commercial, agricultural and international categories with local performance supported by minimal load shedding, increased water demand, and irrigation requirements during dry conditions. International sales increased due to emergency and opportunistic non-firm exports prompted by regional hydropower shortages, alongside new firm supply agreements with Botswana, Namibia and Zambia.

4.2.3.1 Decision vs Actual sales volumes

TABLE 5: SALES VARIANCES PER CUSTOMER CATEGORY (GWH)

Customer Category	Decision FY2025	Actuals FY2025	Variance
Agricultural	5 172	5 286	114
Distributors	82 661	78 993	(3 669)
Commercial	9 774	10 071	297
Industrial	43 459	43 045	(414)
IPP	108	109	1
Mining	27 562	27 239	(323)
Residential	2 746	2 304	(442)
Prepayment	7 200	6 269	(931)
Public lights	207	203	(4)
Traction	1 894	1 673	(221)
Dx international*	112	213	101
Internal sales	462	349	(113)
Total Distribution sales	**181 359**	**175 754**	**(5 605)**
International sales (SAE)	10 587	14 319	3 732
Total sales to all customers	**191 946**	**190 073**	**(1 873)**

Note: * Dx international is reflected under international sales in AFS disclosure

The FY2025 NERSA determination for total local sales was 181 359 GWh, as in the table above, while the actual sales volumes were 175 754 GWh translating into a variance of 5 605 GWh. All categories of sales have a negative variance except for Commercial, Agriculture and IPP's, which means that Eskom sold less than the determination volumes.

Redistributors recorded the highest negative variance at 3 669 GWh, driven by multiple factors. City Power and the City of Tshwane implemented load reduction measures from June 2024 through February 2025 to safeguard infrastructure. Additionally, Ekurhuleni was significantly affected by the decline in industrial sales.

The prepayment category had the second highest negative variance of 931 GWh. The lower sales in this category are attributed to illegal connections and meter tampering.

The residential category recorded a negative variance of 442 GWh. In more affluent areas, customers have increasingly adopted alternative energy sources such as solar and gas. Additionally, conversions to prepaid metering contributed to lower sales volumes.

Industrial sales were 414 GWh below the determination. Customers in the steel sector faced several operational challenges, with Bright Alloys and SA Steel Mills reducing their load, resulting in a combined impact of 218 GWh. The ferrochrome market also experienced difficulties, leading to furnace shutdowns amongst some customers. Additionally, other industrial customers produced at lower-than-expected levels due to market and economic pressures.

The mining category recorded a negative variance of 323 GWh. Anglo Platinum Polokwane experienced a partial furnace shutdown, while Rustenburg Platinum Mines suspended furnace operations due to flooding. Additionally, Sibanye Gold shut down 1 shaft and downgraded another from 26MVA to 4MVA, reducing their planned consumption by approximately 200 GWh.

Commercial sales reflected a positive variance of 297 GWh compared to the determination. This category is highly sensitive to load shedding; consequently, it fell below the determination during FY2024 when load shedding was prevalent. In the absence of load shedding, consumption rebounded. Additionally, Rand Water Board increased usage due to heightened demand for potable water. Customers not included in the original determination contributed to this positive variance, notably Vantage Data Centre.

Traction sales saw a negative variance of 221 GWh. This was primarily due to vandalism of infrastructure and cable theft that significantly disrupted train operations. In KwaZulu-Natal, the coal line experienced substantial reduction in load as some coal haulage shifted to road transport. The agricultural category was impacted by dry weather conditions in regions such as the Northern Cape resulting in increased irrigation requirements, contributing to the overall 114 GWh positive variance.

Distribution International Sales recorded a positive 101 GWh variance aided by the transition of Nampower servicing to Distribution.

4.2.3.2 International sales variances

International sales volumes in FY2025 were higher than the NERSA revenue decision. The details of volumes sold per trading partner are outlined in the table below.

TABLE 6: INTERNATIONAL SALES VOLUMES (GWH)

International Sales (GWh)	Decision FY2025	Actual FY2025	Variance
Botswana (BPC)	118	771	653
Lesotho (LEC) *	240	581	341
Mozambique			
- EDM	48	67	19
- Motraco	8 280	7 806	(474)
Namibia			
- Nampower	613	1 079	466
- Skorpion	-	-	-
- Orange River Cross-border supply (ORC)	125	-	(125)
Eswatini (EEC)	677	871	194
Zambia			
- ZESCO	-	1 643	1 643
- Copperbelt Energy Corporation (CEC)	-	204	204
ZESA	438	1 083	645
Short-term energy market	48	214	166
Total SAE International Sales (excl. Dx Int sales)	**10 587**	**14 319**	**3 732**

Note: * Excludes standard tariff sales to Lesotho

Energy exports in FY2025 were higher than the NERSA determination, this was mainly attributable to the following reasons

- **Botswana Power Corporation (BPC):** Higher sales to BPC was due the utility experiencing self-generation challenges and therefore relied on Eskom to close the deficit. A firm power supply agreement was concluded in June 2024 resulting in additional sales to BPC.
- **Lesotho Electricity Company (LEC):** Higher sales volumes was attributable to LEC increased reliance on Eskom during the Lesotho Muela hydrogenator outage from 1 October 2024 to 31 March 2025.
- **Electricidade de Mozambique (EDM):** Sales were higher than the NERSA determination due to the agreement being on a standby basis.
- **NamPower:** The NamPower contract was increased from 100MW to 170MW from 1 July 2024 due to the drought in the region.
- **Eswatini Electricity Company (EEC):** higher sales volumes than determination, due to higher irrigation requirements.
- **Zambia Electricity Supply Company (ZESCO):** New bilateral contract was concluded with ZESCO due to the drought in the region which was not included in the MYPD revenue application assumptions.
- **Copperbelt Energy Corporation (CEC):** non-firm sales that were not included in the NERSA decision, as these sales to CEC are dependent on CEC securing a wheeling-path.
- **Zimbabwe Electricity NTCSA and Distribution Company (ZETDC):** Sales were higher than the NERSA determination as ZESA continues to have a supply deficit exacerbated

by the drought in the region, as well as a level of interchange energy supply to the control area.

Partly offset by lower sales from the following trading partners:

- **Mozal Aluminium Smelter:** Lower sales than the determination was due to potlines being disconnected, returning on a phased recovery basis
- **Orange River Cross-border:** Sales, if any will be included in Eskom Distribution due to lower voltage supply.

4.2.3.3 Approach to revenue variance related to changes in sales volume

The revenue variance is related to the sales volume variance. When NERSA makes a decision on the sales volume, it allows Eskom to recover the allowed revenue through the sales volume.

It is further clarified that the MYPD Methodology requires the recovery of the **total** variance in revenue. The methodology does not refer to any further adjustment for fixed and variable costs. In addition, no adjustment in revenue is required for any capacity availability. Thus, it is not necessary to determine the fixed and variable cost components to determine the revenue variance. The variable cost elements are addressed when volume related variable costs are considered. This demonstrates the elegance of MYPD methodology.

The NERSA MYPD5 RCA for FY2023 decision supports that Eskom is required to recover the allowed revenue as reflected in the decision. However, these revenues are only fully recovered if all the sales are achieved as assumed in the decision. **Therefore, in the event of lower sales relative to the NERSA determination materialising, it results in Eskom not recovering the allowed revenue assumed by NERSA.**

5 Factors which influence Production plan changes

5.1 Actual Production Plan FY2025

In FY2025, total energy sent out amounted to 218.6 TWh. The details of the source of energy are reflected in the table below.

TABLE 7: FY2025 ELECTRICITY OUTPUT (GWH)

Electricity Output (GWh)	Decision FY2025	Actual Production Plan FY2025
Power sent out by Eskom stations	176 752	195 702
Coal-fired stations (Incl. pre-commissioning)	156 576	179 426
Hydroelectric stations	832	710
Pumped storage stations	4 440	4 649
Gas turbine stations	2 110	2 176
Wind energy	307	332
Nuclear power station	12 487	8 409
IPP purchases	36 923	19 365
Wheeling	2 088	2 028
Energy import from SADC countries	8 678	7 570
Total Gross Production	**224 441**	**224 666**
Less: Pumping	(5 796)	(6 065)
Total Net Production	**218 645**	**218 601**

This is a high-level comparison. It should be noted that energy cannot be easily compared holistically, due to the nature of meeting demand at different timeframes and periods.

Eskom Generation exceeded the assumptions outlined in the Production Plan, primarily due to improved plant performance. The actual EAF for FY2025 was 60.9%, outperforming the 59.1% projected in the MYPD5 application.

Eskom's coal-fired and peaking stations (including pumped storage and hydro) were required to operate at significantly elevated levels. This is mainly due to the IPP programmes not delivering as NERSA had assumed in its decision. The key reasons being delays in IPP projects coming on-line as well as lower-than-expected IPP output. Notably:

- Coal-fired stations achieved a year-end EUF of 92%, which is higher than anticipated.
- The coal fleet operated at EUFs ranging between 89% and 97%, substantially exceeding international norms. According to VGB and global benchmarking studies, typical baseload coal-fired power plants are designed to operate at EUFs between 58% (median quartile) and 71% (best quartile) under steady-state conditions. **Continued operation above these levels places considerable stress on plant components, accelerate wear, and increases the frequency and intensity of required maintenance interventions – this is not a sustainable approach.**

This high utilisation was necessary to minimise load shedding but resulted in operations well beyond optimal thresholds. Elevated usage placed additional stress on plant components, necessitating more frequent maintenance interventions to reduce the risk of breakdowns and ensure continued reliability.

5.1.1 Energy from Eskom Coal fired power stations

For the FY2025 revenue application, the assumption was that these power stations would provide 156 134 GWh of energy. However, the energy produced from the Eskom coal fired power plants was 179 426 GWh. This level was only achieved through increased utilisation of all coal fired power plants to above 90%. The planned maintenance undertaken was higher than projected, enabling Eskom to successfully execute further philosophy-based maintenance. Additionally, the unplanned outages were lower than anticipated, contributing to a higher-than-planned EAF by year-end.

5.1.2 Energy from IPPs

The DEE and National Treasury determine the IPP allocations to be included in Eskom’s revenue application. Eskom does not have the authority to amend or review these allocations. In FY2025, the NERSA-approved IPP contribution was 36.9 TWh, yet actual production reached only 19.4 TWh, a deficit of 17.6 TWh. The assumption that Eskom’s coal-fired fleet could effortlessly absorb the shortfall in IPP generation was overly optimistic.

5.1.3 Energy from Eskom OCGTs

The utilisation of Eskom OCGTs was projected at 2.5 TWh (12% LF) for FY2025 in the application. However, Eskom utilised 2.2 TWh (10.4% LF) by the end of the financial year due to improved plant availability.

5.1.4 Observations

Eskom faced substantial pressure to meet electricity demand during FY2025, necessitating elevated utilisation of its coal-fired generation fleet to avoid or minimise rotational load shedding. High utilisation rates have accelerated wear and tear, requiring sustained investment in refurbishments and predictive maintenance. This strain was further compounded by lower-than-expected energy contributions from IPPs and international imports. Despite these challenges, improvements in Eskom’s EAF played a critical role in stabilising supply. As a result, the impact of load shedding was significantly reduced, with only 13 days of rotational load shedding recorded throughout the financial year.

6 Generation Performance

6.1 Generation Performance Turnaround Strategy

In FY2025, Eskom continued to implement a comprehensive Generation Performance Turnaround Strategy to address persistent generation capacity shortfalls and restore fleet reliability. Central to this approach was the continuation of the “no further shutdowns” strategy (Continued operations). The change in strategy, represents a significant departure from the assumptions made during the MYPD 5 Revenue Application (Shutdown Strategy – Ramping down of units). Consequently, cost assessments should be realigned to reflect the requirements of the Continued Operations and Generation Recovery Plan as detailed in this application.

6.2 Generation Recovery Plan

The Generation Operational Recovery Plan, approved by the Eskom Board in March 2023, remained the cornerstone of the generation turnaround strategy through FY2025. The plan’s primary objective is to improve the EAF by reducing load losses and restoring reliability through intensive, structured maintenance. The strategy emphasises long-term fleet recovery rather than short-term emergency interventions and is designed to improve both technical and environmental performance.

Successful execution of the Generation Recovery Plan has led to a significant improvement in the reliability, efficiency and availability of the coal-fired generation fleet over the past year. The recovery in generation plant performance was made possible by access to funding through government support, improved risk management; increased focus on ancillary plant performance, spares availability, quality of outage execution and skills; and involving original equipment manufacturers (OEMs) when executing planned maintenance.

Average EAF at 60.9% for the year is significantly higher than the previous year (2024: 54.56%). The improvement in plant availability is largely due to a notable decrease of around 4 000MW (about four stages of loadshedding) in UCLF to 25.9% (2024: 32.34%), coupled with a decrease in other load losses (OCLF) to 0.6% (2024: 1.06%). Planned maintenance (PCLF) increased to 12.66% (2024: 12.04%) due to ongoing efforts under the Generation Recovery Plan to improve the performance of the generation fleet over the longer term through focused maintenance.

The improved performance also reflects the successful return to service of key units, including Kusile Units 1, 2 and 3 and the commercial operation of Kusile Unit 5 on 30 June 2024.

The generation fleet continues to operate under considerable strain. The average EUF for coal-fired stations remained elevated at 92% (2024: 96.51%), well above the international norm of around 75% for a fleet of this age. This high utilisation rate, while necessary to meet demand in the shorter term, accelerates wear and contributes to increased unplanned outages in the medium to longer term.

These performance trends highlight the importance of sustained investment in midlife refurbishments, predictive maintenance and digital diagnostics to extend asset life and improve reliability. We must also reduce EUF to sustainable levels by adding new dispatchable capacity and continuing improving plant reliability. Eskom's collective focus remains on further reducing unplanned unavailability to consistently overcome the need for loadshedding

6.3 Observations

The Generation Performance Turnaround Strategy has fundamentally reshaped Eskom's operational trajectory. Through disciplined execution of the Generation Recovery Plan, improved maintenance planning, and stronger institutional governance, Eskom successfully restored fleet stability and delivered a sustained reduction in loadshedding throughout FY2025. The continuation of these programmes, coupled with the sustained operation of strategic coal units through 2030, remains essential to maintaining supply security and consolidating performance gains achieved during the year.

7 Primary Energy

7.1 Primary energy variances and RCA impact for FY2025

Total primary energy costs in the FY2025 revenue decision were R185.6bn. Eskom incurred primary energy costs of R151.8bn in the year which resulted in a negative variance of R33.8bn. An adjustment of R8.7bn was made to the OCGT usage which related to the SARS diesel rebate. The adjustment reduces the total primary energy to a negative variance of R25bn for the benefit of the consumer. Refer table below for the RCA variance for total primary energy.

TABLE 8: TOTAL PRIMARY ENERGY (RM)

Primary Energy (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Coal usage	71 863	76 191	4 328	-	4 328
Water usage	3 165	2 911	(254)	-	(254)
Fuel and water procurement	335	320	(15)	-	(15)
Coal handling	2 507	3 179	672	-	672
Water treatment	669	774	105	-	105
Sorbent usage and handling	311	155	(155)	-	(155)
Gas and oil (coal fired start-up)	4 064	7 496	3 432	-	3 432
Nuclear	1 031	588	(443)	-	(443)
Coal and gas (Gas-fired)	10	2	(8)	-	(8)
OCGT fuel cost	8 862	(879)	(9 741)	8 741	(1 000)
Road repairs	-	1	1		1
Eskom Primary Energy	**92 817**	**90 738**	**(2 079)**	**8 741**	**6 662**
Independent Power Producers (IPPs)	76 970	47 273	(29 697)	-	(29 697)
International Purchases (SAE)	9 334	6 540	(2 794)	-	(2 794)
Environmental levy	6 503	7 270	767	-	767
Carbon tax	-	3	3	-	3
Total Primary Energy	**185 624**	**151 824**	**(33 800)**	**8 741**	**(25 059)**

Note: Demand response, Power alerts and Dx International purchases is addressed separately

As is reflected in the table above, the key variances are due to the OCGT fuel costs, coal usage costs, costs related to gas and fuel oil for the start-up of coal fired power stations, international purchases and IPP costs. Some of these variances are in favour of Eskom and some in favour of consumers. NTCSA incurred a carbon tax liability for CO2e emissions in category 1A3a (domestic aviation) and 2G1b (SF6 leaks).

With the summary information disclosed, the subsequent sections will provide more detail on the respective primary energy components.

7.2 Coal Costs

7.2.1 Mandate and background

Eskom's mandate is to safely and sustainably identify, develop, source, procure and deliver the necessary amounts of coal of the required quality for Eskom's power stations, at the right time and at optimal cost. The assumptions that informed the application, and the corresponding reality, are stated in the assumption tables in the relevant sections.

7.2.2 FY2025 Reasons for decision

NERSA's reasons for decision stated that:

- The Energy Regulator will adjust and factor the relevant quantified expenses from investigations into coal contracts into **future** Eskom revenue decisions.
- The Energy Regulator determined the following coal burn costs per contract type:

TABLE 9: COAL BURN COSTS PER CONTRACT TYPE NERSA DECISION

Coal Burn FY2025 Revenue Decision (Rm)	Cost-Plus	Fixed Price	Medium Term	Total
Decision burn cost (R 'm)	26 755	18 976	26 132	71 863

7.2.3 FY2025 Assumptions

The FY2025 revenue application was based on certain assumptions. During the year, some of these assumptions were realised while others were not. The differences in assumptions and the explanations are provided in each part of the document.

TABLE 10: ASSUMPTIONS

Application FY2025	Actual FY2025
Electricity production from coal fired plant would be 156 134 GWh.	Electricity production from coal fired plant was 179 426 GWh, including pre-commissioning burn of 1 053 GWh. One of the contributing factors was the inability for IPP's to deliver energy assumed by NERSA in its decision.
Cost-Plus produce at expected levels, which are below contractual volumes	Total production from the Cost-Plus mines was higher than expected. Production from Kriel and Matla mines was lower than expected.
Fixed Price mines produce at contractual levels, except for MMS which produces below contractual volumes.	Production was lower than expected. MMS produced below expected volumes. Matimba Power Station could not accept all the contracted coal. Generation at Matimba and Medupi Power Stations was lower than expected, and full stockpiles meant that the contractual volume of coal could not be taken at Matimba.
Kriel and Matla CSAs will be extended	The Kriel CSA has been extended. Negotiations to extend the Matla CSA are continuing.

7.3 Total Coal Costs for FY2025

The table below compares the coal costs in the MYPD5 revenue decision for FY2025, to the actual coal burn expenditure for FY2025. The variance explanations that follow for each category of expenditure are for the difference between the application and the actual expenditure.

TABLE 11: TOTAL COAL BURN COSTS (RM)

Coal Burn (Rm)	Decision FY2025	Actual FY2025	Variance
Cost-Plus	26 755	24 949	(1 807)
Fixed Price	18 976	18 944	(32)
Medium Term	26 132	32 298	6 166
Total Coal Burn Cost	**71 863**	**76 191**	**4 328**

Note: For each category, the relevant regulatory rules and methodology are explained followed by the reasons for the regulatory decision as per NERSA. Then the reasons for the variances are discussed.

7.3.1 NERSA MYPD methodology requirements

The Energy Regulator will approve the coal benchmark price (i.e., average R/ton) per contract type (Cost-Plus, Fixed Price, Medium-Term and Short-Term) and Alpha for each contract type in the MYPD decision (MYPD Methodology par 12.2.1). The coal benchmark price is determined by the Energy Regulator to be used in comparison with the actual coal cost for the purpose of determining pass-through costs. The coal benchmark price will be compared to Eskom’s actual cost of coal burn (R/ton) using a Performance Based Regulation (PBR) formula. The PBR formula is the maximum amount to be allowed for pass-through, calculated by applying the following formula per contract type:

PBR COST (RAND) CALCULATION

PBR cost (Rand) *= (Alpha x Actual Unit Cost of Coal Burn + (1 – Alpha) x Coal burn Benchmark price) x Actual Coal Burn Volume.*

7.3.2 Implementation of MYPD methodology

Applying the MYPD methodology formula, the variances per contract type are illustrated in the table below. A coal burn price variance of R5 162m for the benefit of the consumer and a coal burn volume variance of R10 060m contribute to an overall coal cost variance of R4 898m for the benefit of Eskom. This indicates that coal was secured at a lower average price than determined by NERSA and volumes of coal utilised was more than that determined by NERSA. The variance is capped at the difference between the actuals and decision of R4 328m.

TABLE 12: COAL BURN RCA VARIANCES BREAKDOWN FOR FY2025 (RM)

Coal burn variance breakdown (Rm)	Cost-Plus	Fixed Price	Medium Term	Total
Coal burn price variance	(2 278)	2 228	(5 112)	(5 162)
Coal burn volume variance	591	(2 377)	11 846	10 060
Coal burn costs included in RCA	**(1 687)**	**(149)**	**6 734**	**4 898**

Note: The total burn variance is R4 898m in favour of Eskom, comprising a price variance R5 162m and a volume variance of R10 060m. After applying the PBR formula, the variance is capped at the difference between the actuals and decision.

7.3.3 Coal Burn Cost

Coal burn is derived from opening stock being added to purchases as illustrated in the table below. A coal burn cost of R71 054m was included in the revenue application. NERSA determined the coal costs to be R71 863m. This net increase was a result of:

- NERSA increasing the production from coal-fired plant while reducing the production from the OCGT plant.
- NERSA decreasing the burn rate and, therefore the volume of coal required.

However, it is not clear what coal purchases costs or what coal volumes were used to arrive at the burn cost as the reasons for decision do not include coal purchase costs. Eskom, thus, compares the application to the actual purchases. Thus, motivations provided compare actuals to the application. Actual coal burn cost was R76 191m as shown in the table below.

TABLE 13: COAL BURN DERIVED (RM)

Coal Burn (Rm)	Decision FY2025	Actual FY2025	Variance
Opening stock	No Breakdown in RfD	19 785	No Breakdown in RfD
Purchases		75 455	
Closing stock		(19 049)	
Commercial coal burn	**71 863**	**76 191**	**4 328**

The total variance between actual burn cost and what was determined is R4 328m, with the actual cost being higher than the determination. Total coal burnt was 11 631 ktons more than assumed in the application and 10 707 ktons more than the decision. The coal fired power stations generated 23 292 GWh (including pre-commissioning energy) more than assumed.

The analysis below is an explanation of the actual FY2025 costs versus the costs and volumes for FY2025 that were included the revenue application.

Coal burn costs and volumes are derived from coal purchases. The coal purchases as per the revenue application are compared to the actual FY2025 coal purchases to explain the difference in the burn costs and volumes. Total coal purchases volumes were 12 646 ktons more than assumed in the Eskom application. The higher volumes were due mainly to more energy being produced from coal -fired power stations. Purchases were higher on the Cost- Plus and Medium-Term contract types.

The average price Eskom pays for coal is determined by the volume of coal procured from each type of contract and the price of coal from each type of contract. The R/ton coal price was R80 (10%) lower than the application on average. This is mainly a result of the mix of coal purchases between the contract types.

The R/ton cost from the Cost-Plus contracts was 13% lower because of lower costs and higher volumes. Fixed Price production was 7% lower while costs were lower by 11%, resulting in the R/ton being 4% lower. Volumes on the ST/MT purchases were 43% higher, with the ST/MT purchases cost being 22% higher, but the ST/MT price (in R/t) was 15% lower.

The coal price (R/ton) is impacted by various factors:

a. Cost-Plus contracts

Most of the Cost-Plus mines are no longer able to produce contractual volumes. Capital underinvestment in the mines together with historic over supply and the age of the mines has made underproduction the norm in the recent past. The mines attempt to supply expected volumes. However, it is not possible for the mine to supply contractual volumes without having invested in sufficient capital expenditure. When more detailed requirements are known, discussions are held with the mine. Eskom and the mine will agree on the volume to be produced. The age of the mines and historical supply profiles compound the production challenges. In FY2025 application, Eskom assumed production levels lower than contractual volumes because of these factors and because of the delay in investment in the mines.

The unit price (R/ton) of coal from the Cost-Plus mines is the total cost of operating that mine for that period divided by the production volumes. The export price has little direct impact. During FY2025, the volumes from Cost-Plus mines were higher than what was expected. The Cost-Plus mines provided approximately 36% of the coal procured in FY2025 against the assumption in the application of 39%.

It is the nature of the Cost-Plus agreement that Eskom pays for all expenditure incurred at the Cost-Plus mines, irrespective of the level of production. Lower production results in a higher R/ton. Historically, when Eskom required the Cost-Plus mines to supply coal volumes in excess of their contractual obligations, the mines were willing to do so. The only cost to Eskom, and the consumer, was the variable rate of return that the mines earned, so it was cheaper than buying coal elsewhere. Between 1996 and 2011, the Cost-Plus mines supplied Eskom's power stations 51.6 Mt more than their contractual volumes. The impact of this has been felt in the more recent past. The mines depleted reserves that would have been supplied to Eskom in later years. As electricity demand increased, additional reserves needed to be accessed, and new equipment was required. Because of funding constraints, future fuel expenditure on the Cost-Plus mines is one of the items that was reduced. The result has been lower than contractual production from these mines and a consequent increase in the R/ton cost. Eskom has resumed investment, and expects to see the benefit thereof, but it is envisaged that production will be maintained instead of increased in the short to medium term.

Coal procured from the Cost-Plus contracts was 2 140 ktons higher than in the application. The total spend was R2 225m lower than in the application and the R/ton was R98/ton lower.

b. Long term fixed price contracts

This category comprises the Duvha (MMS), Matimba (Grootegeluk) and Medupi (Grootegeluk) contracts. The price is determined by the terms of the contract, e.g., an annual escalation is applied to the price established at the inception of the contract. The contract will stipulate how the escalation is to be calculated. None of the existing contracts are impacted directly by the price of export coal. Approximately 25% of coal for FY2025 was sourced from long term fixed price contracts against an assumption in the Eskom application of 31%.

The total average R/ton cost for fixed price coal at Duvha was higher than the application. The average R/ton was lower at Matimba and Medupi.

The volume of coal was 2 062 ktons less than assumed in the application. The total spend on the long-term fixed price mines was R2 135m lower than the application. The average R/ton was R24/ton lower.

c. Short Term/ Medium Term (ST/MT) contracts

These contracts are of varying durations. They are essentially fixed price contracts but are differentiated from the original long-term fixed price (40-year) contracts referred to above because they are much shorter in duration. NERSA differentiates further by separately identifying contracts less than three years in duration as short term and those longer than three years as medium term. Eskom does not make this distinction for internal purposes but has done so for purposes of the RCA calculations as per the methodology.

Apart from the duration, both these contract types have similar terms and conditions. The suppliers supply contractual volumes. As with the long-term fixed price contracts, the price is determined by the terms of the contract, e.g., an annual escalation is applied to the price established at the inception of the contract. The contract will stipulate how the escalation is to be calculated. The export price may have an impact in that the supplier may reference this price at the time of negotiation. However, Eskom will always negotiate a fair price within the environment at the time. Whether this price correlates to the export price at any given time is likely to be coincidental. These contracts supplied approximately 38% of the coal in FY2025 against the assumption in the application of 30%.

In FY2025, Eskom purchased 12 568 ktons more on ST/MT contracts than expected. The total spend on ST/MT purchases was R5 793m (5%) more than assumed, but the R/ton was 15% lower than expected (R133/ton). This includes the cost of transporting this coal from source to the power stations.

Contracts longer than 12 months escalate annually on the anniversary date. The escalation is therefore specific to each contract, depending on when the contract was concluded. The coal price is escalated by a basket of indices as specified in the contract. The indices used will be those specific to that base date and the escalation dates, so indices will differ for each contract. The escalation basket is reviewed periodically for structural changes in the industry which may need to be affected in the basket. The weightings of the indices may differ depending on the type of mining operation. The following formula is an illustration of how the annual contract price adjustment is calculated for ST/MT contracts.

TABLE 14: CONTRACT PRICE ADJUSTMENT ILLUSTRATION

Contract Price Adjustment illustration	Weight	B (previous index)	Base Date	L (new index)	Escl Date	(L-B)/B	Weighted Avg
Labour	0.26	16752.2	14-Apr	18 264	15-Apr	0.09	0.02
Diesel	0.15	1329.75	14-Apr	1 171	15-Apr	-0.12	-0.02
Electricity	0.04	106.7	14-Apr	119	15-Apr	0.11	0
Mining Machinery	0.13	113.5	14-Apr	114	15-Apr	0	0
Overheads CPI	0.1	109.1	14-Apr	114	15-Apr	0.04	0
Profit & Capital Rec	0.22	109.1	14-Apr	114	15-Apr	0.04	0.01
Fixed	0.1		14-Apr		15-Apr		-
Total	1						-
Annual PAF (1 + sum)							1.02
Base Price							12.7
Adjusted Price							13.02
New price							13.02

Eskom does not purchase coal on the spot market. All coal purchased is negotiated in advance, and a contract is signed when the parties reach agreement on financial and technical parameters. The process of contracting includes Eskom's governance process and can take more than a year from inception to coal being contracted. Once Eskom has signed a contract, it is obliged to either take the coal or pay for the coal even if it does not take it. This contractual obligation means that Eskom incurs these costs irrespective of whether electricity demand, and production, declines. In the coal value chain, this is not unreasonable. The coal miner will make necessary investments to produce the coal. These investments are typically fixed, significant in value and recouped over the medium to long term. To raise funds, the supplier needs to prove that they will have the income to service the debt. A contract provides this assurance. On Eskom's side, providing the miner with this assurance enables Eskom to negotiate a better price for the coal.

The factors above contribute to the argument that a significant portion of Eskom's coal costs are largely fixed and unavoidable in nature.

7.3.4 Coal transport

Coal may be transported by conveyor, rail, road or a combination of modes. ST/MT coal is typically unable to be transported by conveyor. The mode of transport for FY2025 is reflected in Table below.

TABLE 15: COAL TRANSPORTED (TONS)

Transport Mode	Application FY2025	Decision FY2025	Actual FY2025	Variance (Actual - Application)
Conveyor	68 093	No breakdown in RfD	65 761	(2 332)
Rail	13 167		2 747	(10 420)
Road	13 386		38 784	25 398
Total	**94 645**		**107 291**	**12 646**

Conveyor is the cheapest mode of transport. The Fixed Price and Cost-Plus mines, which are located close to the stations, use this mode. Under offtake from Grootegeluk mine by Matimba and Medupi Power Stations made up more than half of the volume difference on conveyor. Lower than expected production at Arnot colliery also contributed to lower volumes over conveyor.

Rail is the next cheapest mode of transport. Utilisation of this mode of transport is constrained by the fact that only Majuba, Tutuka and Camden Power Stations presently have rail infrastructure. Lower ST/MT purchases and Transnet Freight Rail's lack of capacity resulted in significantly lower volumes of coal being railed compared to the application. Even where a power station has the necessary rail infrastructure, not all suppliers have access to a rail facility. It is rare that one of the smaller mines have direct access. The coal needs to be transported by road to a rail siding, offloaded and then reloaded onto a train. Where this is possible, these additional steps in the logistics process add to the delivered cost of coal. Where this is not possible, coal is transported by road to the power station.

Almost all power stations acquired coal on ST/MT contracts. Where this coal could not be transported by rail, it was transported on road. Because of the rail infrastructure constraints, ST/MT coal to the power stations is transported by road or a combination of road and rail (multi-mode transport). Road is usually more expensive than rail, but where multi-mode transport is used, this mode may be more expensive than road alone.

7.3.5 Coal Qualities

Many of the mines supplying Eskom have been operating for a long time. Older mines have a deteriorating reserve/resource base, while higher coal qualities are required to compensate for older plant and tighter environmental legislation. Eskom has revised the coal quality specifications accordingly. Eskom is including the revised qualities in all new coal supply agreements. In the case of legacy coal contracts, the qualities are based on the original station design requirements. Where possible, Eskom has requested suppliers to improve the qualities. Coal-related load losses for FY2025 were dominated by Matla power station at 91% while Grootvlei and Majuba contributed 7% and 2% respectively. Coal quality has generally improved at most power station which has resulted in minimum coal related OCLF at stations (Kriel, Camden, Tutuka, Kendal, Arnot and Grootvlei). The overall coal related OCLF for FY2025 was 0.37% against a target of 0.65%.

7.3.6 Coal stock

The value of closing stock at the end of FY2025 was R19.82bn while total closing stock days were 79. Total stock levels translate to coal volumes of 37 847 ktons. If the stock at Medupi and Kusile Power Stations were excluded, stock days declined to 42 days. The impact of the delays in the completion and commissioning of these stations is still evident. This was compounded in FY2024 and FY2025 because of the collapse of the chimney at Kusile Power Station. This resulted in three units being offline. Two units returned to service in February and March 2025. The third unit returned during FY2026. The nature of coal contracts is that Eskom either accepts the coal or pays for the coal anyway. In these circumstances, Eskom opts to accept the contractual coal.

7.4 Water usage costs

7.4.1 FY2025 Reasons for decision

As noted in the NERSA reasons for decision related to the FY2025: “The increase in water costs in the 2023/24 and 2024/25 financial years is less than inflation at 4.5% and 4%, respectively. However, water consumption volumes were adjusted to 1.42l/kWh to reflect those on Eskom’s regulatory financial reports (RFRs). In addition, these costs were further adjusted to account for changes in coal usage.”

7.4.2 Water usage assumptions

TABLE 16: WATER USAGE ASSUMPTIONS

Application FY2025	Actual FY2025
Water consumption per unit was 1.42 litres/kWh at	Water consumption per unit was 1.40 litres/kWh
Current infrastructure is old, and the backlog of maintenance will also result in an increase to the water tariff.	The DWS was unable to carry out all planned maintenance and still has a backlog due to a lack of appointment of a maintenance contractor and long lead times.
Kusile and Medupi will use water for FGD	FGD was not Implemented at Medupi in FY2025.

7.4.3 Water usage costs

NERSA decreased the application of R3 312m for water costs in FY2025 to R3 165m. Actual expenditure was R2 911m resulting in a variance of R254m for the benefit of consumers. The water costs are composed of various tariffs, reflected in the table below. The analysis is between actuals and application, as NERSA did not provide a breakdown in its decision.

TABLE 17: COMPONENTS OF WATER USAGE COSTS (RM)

Water Costs (Rm)	Decision FY2025	Actual FY2025	Variance
PTM Engineering	No breakdown in RfD	6	No breakdown in RfD
O&M		282	
Pumping		748	
CUC		740	
Water Research Levy		20	
Water Resource Charge		487	
VRT		509	
Waste Discharge Charge		5	
Third Party Credit		-49	
Lab Services		2	
CMA		15	
Total Coal Stations Only	**-**	**2 768**	**-**
Peaking stations	No breakdown in RfD	135	No breakdown in RfD
Renewables		0	
Nuclear - Koeberg		6	
Group Capital		2	
Total Generation water costs	**3 165**	**2 911**	**(254)**

The price of water is impacted by the tariffs that government gazettes. Eskom assumed water related costs would increase by between 6% - 8%. In actual mode, total costs are impacted by actual legislated tariffs and the volume of water consumed. Aside from Operating and Maintenance and Pumping costs, tariffs are legislated and beyond Eskom's control. The largest contributions to the variance between the application and actual costs are operations and maintenance, pumping costs, waste discharge charge and capital unit charge.

7.4.3.1 Operations and Maintenance

These are costs incurred to maintain the water schemes' infrastructure. Eskom pays the actual costs incurred by the Department of Water and Sanitation (DWS). The DWS conducts all repairs and maintenance on water pipelines and charges the costs to Eskom as per the memorandum of agreement. Eskom does not control or manage this maintenance. In recent years, the DWS has consistently underspent on maintenance. Eskom has escalated this risk to the Director General of DWS.

7.4.3.2 Pumping costs

Pumping costs are the electricity costs incurred to transport water. The lower-than-expected electricity tariff increases, and lower inter-basin transfers resulted in a positive variance on the cost of pumping of water within and between water schemes.

7.4.3.3 Capital unit charge (CUC)

This is a legislated tariff. The Trans Caledon Tunnel Authority (TCTA) needs to recover the full cost of the pipelines, including the financing cost for the repayment of the loans for the projects they have executed for industrial users. The repayment is charged per unit of water consumed. The tariff on the Mokolo Crocodile Water Augmentation Project (MCWAP) was lower than expected. This was the primary reason for the variance in the CUC.

7.4.3.4 Vaal River Transfer (VRT)

This is a legislated tariff. VRT is paid on all water that is sourced from the Vaal River scheme. The Vaal Water system is also the system of last resort. Water is drawn from the Vaal to supplement the other systems. For FY2025, the actual tariff was lower than expected.

7.4.3.5 Third Party Credit

Eskom pays for all the water extracted from the schemes. Where third parties use water, for which Eskom has paid, the DWS credits the cost of that water to Eskom.

7.4.4 Water volumes

The volumes of water consumed are driven primarily by the electricity produced by power stations. The volume consumed to generate a unit of electricity varies per power station. The total consumption will depend on the mix of stations used to generate electricity, with older stations consuming more. Most of Eskom's stations are beyond the halfway mark of their lifespans. Although the coal fired stations produced less than assumed, actual water consumption per unit of electricity was higher at most stations than was assumed, resulting in a total increase in water used. The overall water performance at coal fired power stations for FY2025 was 1.40 l/kWh. The stations consumed 41.272 million litres more than expected, having generated 23 292 GWh more from coal-fired plant. Ageing water infrastructure also contributed to higher consumption.

7.5 Fuel & Water procurement

TABLE 18: FUEL & WATER PROCUREMENT (RM)

Fuel & Water Procurement (Rm)	Application FY2025	Decision FY2025	Actual FY2025	Variance
Manpower	182	182	204	22
Consulting fees	10	10	9	(0)
Legal fees	92	92	11	(82)
Travel and subsistence	4	4	1	(3)
Other	47	47	94	47
Total	**335**	**335**	**320**	**(15)**

7.5.1 NERSA methodology requirements

The methodology applicable to FY2025, as published during 2016 stipulates more detail which is required for other Primary Energy costs. The fuel and water procurement costs have been included as prudent costs in recent NERSA decisions. Fuel and water procurement expenditure had a variance for the benefit of the consumer of R15m. The primary components of fuel and water procurement expenditure and the reasons for the bulk of the variances in expenditure are:

7.5.1.1 Employee benefit costs

Employee benefit costs comprise the bulk of the fuel and water procurement costs. These costs include all salaries, allowances, company contributions and legislated costs such as workman's compensation and skills development payments. Following multiple years during which financial constraints resulted in recruitment of new employees being halted, Primary Energy Division (PED) filled some of the critical vacancies in the department.

7.5.1.2 Legal fees

Legal fees have a variance in favour of the consumer. in FY2025. Eskom makes an application based on the information available at the time. In FY2025, a case between a coal supplier and Eskom was resolved in favour of Eskom.

7.5.1.3 Other

'Other' costs include the corporate overheads allocated to the Primary Energy Department, insurance, marketing and subscriptions to databases that are relevant for the business. The largest expense in this category is insurance cost for the Komati Water Scheme.

8 Other Primary Energy

The MYPD Methodology allows for other primary energy variances as pass through. Coal burn, OCGTs, IPPs and environmental levy have specific rules and are dealt with separately in the document.

MYPD Methodology - Other Primary Energy Costs

17.1.1.2 Allowing for the pass-through of prudently incurred primary energy costs as per section 12 of the methodology.

8.1 Other Primary Energy FY2025 Overview

Between FY2024 and FY2025, Eskom's other primary energy cost profile shifted in line with improved generation performance and a significant reduction in loadshedding. Coal handling and water treatment costs increased due to higher coal output and greater operational activity across the baseload fleet, as units ran more consistently to meet demand. Continuous operation required more coal handling equipment usage and maintenance, driving proportional increases in variable costs.

Conversely, startup gas and fuel oil expenditure declined, reflecting fewer plant restarts and more stable operation of coal-fired units. In FY2024, frequent unit trips and emergency restarts had increased these costs, whereas in FY2025, improved reliability and fewer outages reduced the need for ignition fuels. Overall, changes in these primary energy components mirror Eskom's transition from crisis-driven, stop-start generation to steadier, higher-efficiency operations.

The change in strategy, as outlined in the generation performance section above, represents a significant departure from the assumptions made during the MYPD 5 Revenue Application (Shutdown Strategy – Ramping down of units). Consequently, cost assessments should be realigned to reflect the requirements of the Continued Operations and Generation Recovery Plan as detailed in this application.

8.2 Coal Handling costs

The NERSA MYPD5 Reasons for Decision did not apportion its decision per power station for coal handling costs. In the absence of such apportionment, the RCA motivation will be based on the prudency of actual expenditure

Coal handling refers to all the activities that are necessary to get the coal to the boiler once it has been delivered to the power station storage facilities and coal stockyards via a dedicated mine, road and / or rail. The main cost components of coal handling include labour, machinery & vehicles (such as Articulated Dump Trucks, tipper trucks, bobcats, bulldozers, etc, which are known as white and yellow plant) and maintenance (e.g. conveyor maintenance, travelling chutes, tripper cars, etc). The diesel / fuel for the white and yellow plant is also a significant cost driver.

8.2.1 The Drivers of Coal Handling costs

Coal handling is mainly driven by fixed costs which do not vary with production and / or the level of coal handling activity i.e. Fixed costs in this context refers to labour and machinery anticipated at the time of contracting assuming the station is running at Maximum Continues Rating (MCR). Coal handling although mainly fixed, may vary (i.e. an additional requirement beyond the contracted levels), due to problems experienced for example with the mine in delivering coal to the power station, which may require the power station to build strategic stock due to coal shortages. This will result in an increase in coal handling costs because of the utilisation of more yellow plant (i.e. equipment like graders, trucks, reclaimer etc.) and more labour (overtime). An increase in the utilisation of yellow plant will further result in an increase in fuel / diesel usage.

8.2.1.1 Coal supply constraints

Coal supply constraints may result in coal having to be reclaimed from the strategic stockpile requiring more equipment and labour without an increase in actual production at the power station. Once the supply constraints have been resolved, the effected stockpiles will have to be replenished and rebuilt. Coal handling is not directly correlated to energy sent out – A power station can have the same amount of production but due to varying supply scenarios may result in different coal handling costs (e.g. coal can be supplied directly from the mines via conveyors or reclaimed from the coal stockyard using yellow plant – The latter will be the more costly scenario).

The variable portion (i.e. increased coal handling requiring labour and equipment beyond the minimum contracted levels) of coal handling is when there is double handling of the coal due to the following, but not limited to:

- When there is a trip at the power station (production stops) or feeding conveyors are not available, delivered coal needs to be re-directed to the stockpile, to be reclaimed at a later stage. The reduced performance at stations in terms of UCLF/ trips has, therefore, a direct consequence in terms of increased coal handling costs.

- When there are mine delivery problems, coal needs to be reclaimed from the stockyard / stockpiles by means of mechanised stacker/reclaimers, drum reclaimers or mobile feeders for the units / boiler. For Kusile stockyard startup conditions, the normal operation is to stack coal on the stockyard and reclaim with mechanised equipment for the purpose of homogenisation to supply the boiler with consistent coal quality.
- When a mine supply conveyor breaks, additional handling via bulldozer and or front-end loaders (yellow plant) would be required to manually feed coal into chutes or mobile feeders feeding onto conveyers (for the units / boiler). The cost of conveyor repairs would also be allocated to coal handling.
- Although most power stations do have dedicated mines, these mines sometimes undersupply coal for various reasons ranging from being unable to mine at maximum capacity, moving between coal seams/deposits and/or reaching their end of life. Therefore, mine conveyed coal needs to be supplemented with road delivered coal, which incurs significant handling costs.

8.2.1.2 Contract Type

The Contract type is another factor that needs to be considered in that some of the stations have take-or-pay coal contracts which means that regardless of their production / burn they will have to take and handle the coal delivered as per contract. This coal will have to be transported and stored in a strategic stockpile requiring additional yellow plant resources.

8.2.1.3 Conveyor spills

If a conveyer spills coal, labour is required to manually load the coal onto the conveyor using shovels.

8.2.1.4 Coal Transport

Another differentiation in coal handling costs across the coal-fired fleet is whether a power station has a dedicated mine (coal transported via conveyor to the station) versus whether coal deliveries take place via rail and / or road (the latter generally more expensive from a coal handling perspective because of the use of mobile equipment).

8.2.1.5 Weather conditions

Coal from open cast mines is exposed to weather conditions, particularly rain, which impacts coal handling. The difficulty of handling wet coal requires coal to be reclaimed from the strategic stockpile, therefore increasing coal handling costs.

As explained above, there are various factors which impacts the level of coal handling activities undertaken. Each of these individual circumstances should be assessed on a station-by-station basis, based on the specific circumstances in that particular year.

8.2.2 Coal Handling Costs in FY2025

During FY2025, Eskom's coal handling operations were integral to its electricity generation activities, with coal-fired power stations contributing approximately 80% of total gross electricity output. Eskom applied for coal handling costs of R2 608m, which were subsequently adjusted to R2 507m by NERSA.

Coal handling encompasses the full logistics chain required to deliver coal to the boilers, including coal off-loading, stockpile management, reclaiming, crushing, and conveyor system operation and maintenance. These functions are essential to ensure consistent fuel supply and optimal boiler performance.

The increase in coal handling costs from R2 504m in FY2024 to R3 179m in FY2025 is primarily attributable to higher generation activity and operational stability across the coal fleet. With Eskom reducing loadshedding from 329 days in FY2024 to just 13 days in FY2025, coal-fired units operated more consistently, resulting in:

- Higher coal volumes, as energy sent out from coal stations increased with improved EAF.
- Increased use of heavy machinery and conveyor systems, leading to greater consumption of fuel, lubricants, and spare parts.
- Additional labour and maintenance requirements to support extended operational hours and maintain reliability under higher load conditions.
- Inflationary pressures on diesel, spare parts, and outsourced maintenance contracts, further adding to total handling expenses.
- Continuous operations, while improving efficiency, still drive higher total variable costs.

Overall, the increase in coal handling expenditure reflects higher coal movement and plant utilisation, consistent with Eskom’s stronger generation performance in FY2025.

TABLE 19: SUMMARY OF COAL HANDLING COSTS (RM)

Coal Handling (Rm)	Decision FY2025	Actual FY2025	Variance
Coal handling	2 507	3 179	672

8.3 Water Treatment Costs

The NERSA MYPD5 Reasons for Decision did not apportion its decision per power station for water treatment costs. In the absence of such apportionment, the RCA motivation will be based on the prudency of actual expenditure.

8.3.1 Description of Water Treatment Processes

There are six main water treatment processes:

- Demineralised water production
- Potable water production
- Condensate polishing
- Cooling water treatment
- Ash water treatment
- Sewage water treatment

8.3.1.1 Demineralised Water Production

- Demineralised water is produced at the power station as it is fed to the Generating Units for the production of steam that turns the turbines.
- Raw water is used for the production of demineralised water. It is first treated in a pretreatment plant, which comprises clarifiers and filtration systems, to produce filtered water and potable water. In the pretreatment process, various pretreatment chemicals are used, including coagulants, flocculants, and disinfectants.
- Filtered water is then further treated in the demineralised water production plant. At most stations, ion exchange processes are used for demineralised water production, whereas at a few stations, membrane processes are used to produce demineralised water.
- The ion exchange processes uses ion exchange resin beads, loaded in vessels, to remove ions from the water, thereby demineralising the water. These resin beads have a certain ion exchange capacity and become “exhausted” after a certain run length. The demineralised water production vessels are therefore periodically taken out of service, in order to regenerate the resin, and restore the ion exchange capacity. This resin is

regenerated using chemicals such as sulphuric acid and caustic soda. These constitute the bulk of the demineralised water production cost. The quantity of chemicals used is mainly dependent on the demineralised water production rate and the run length of the ion exchange resins. The latter is influenced by the feed water quality, the condition of the ion exchange resins, and the efficiency of the regeneration process.

- The membrane processes require periodic cleaning of the membranes. The quantity of chemicals used is mainly dependent on the demineralised water production rate, and the run time before cleaning is required. The latter is influenced by the feed water quality, the condition of the membranes and the efficiency of the cleaning process.

- **Factors which contribute to increased chemical usage are as follows:**

  - Change in raw water quality: The design of the demineralised water production process is based on a specific raw water quality. A deterioration in the raw water quality compromises the efficiency of the demineralised water production process and results in more frequent regenerations, additional cleaning measures having to be implemented and a higher chemical cost. Some of the stations have experienced a deterioration in the quality of the raw water and/or quality of the feed water.
  - Deterioration in the availability, reliability and efficiency of the demineralised water production plant: Generation has been experiencing a decrease in the reliability and performance of a number of demineralised water production plants. This results in more chemicals being used in the regenerations, and regenerations not being effective. This in turn results in regenerations being carried out more frequently, and more chemicals being used, increasing the cost of treatment. The refurbishment of the demineralised water production plants has been identified as a priority focus area. Refurbishment plans have been developed for each station and are being tracked.
  - Increase in demineralised water consumption: There has been a significant increase in the demineralised water consumption of generating Units over the last few years, including in the last financial year, over and above the projected assumptions. This has required an increase in the demineralised water production rate, to try to keep up with demand. In some cases, the demineralised water consumption is between 2 and 5 times the station's design demineralised water consumption. This has resulted in an increase in the cost of demineralised water production.

The main contributors to high and increasing demineralised water consumption, and demineralised water losses, across the fleet were the high number of Unit trips (despite being lower than previous years), the high demineralised consumption during the return to service of Units, and the high number of defects on the Units. The stations have developed comprehensive action plans, which list all the contributors, estimate the contribution of each contributor, identify root causes, provide actions to address the root causes, and track execution readiness. The stations track the execution of these action plans.

8.3.1.2 Potable Water Production

- Filtered water is also further treated to produce potable water.
- Potable water is used for drinking purposes at the power station, and is also used in various other processes, including fire protection.
- One of the factors that contributes to the cost of potable water production is the rate of consumption of potable water by the different users.

8.3.1.3 Condensate Polishing

- Some of the power stations use condensate polishing on the Units to control the chemistry of the water and steam within the boiler-turbine circuit.
- Condensate polishing plants utilise ion exchange resin beads, loaded in vessels on the Units, to remove impurities from the water on the Units. When the resin beads are “exhausted” after a certain run length, the resin is transferred to a condensate polisher regeneration plant at the water treatment plant, for the resin to be regenerated. This resin is regenerated using the chemicals, sulphuric acid and caustic soda.
- The quantity of chemicals used for condensate polishing is mainly dependent on the frequency of ion exchange resin regenerations. The latter is influenced by the level of impurity ingress into the water/steam cycle, the condition of the ion exchange resins, and the efficiency of the regeneration process.

8.3.1.4 Cooling Water Treatment

- Most power stations require water for condensing the exhaust steam from the final turbine system. This allows the water within the boiler-turbine circuit to be reused by the condensed steam being fed back as boiler feedwater.
- The condensing of the steam occurs in a heat exchanger called the condenser. Systems that utilise air as the cooling medium are referred to as dry cooling systems. Systems where water is used as the cooling medium in the condenser are referred to as wet cooling systems. These wet cooling systems are commonly known as main cooling water

systems. The table below indicates which stations have dry cooling systems and which have wet cooling systems/main cooling water systems.

TABLE 20: MAIN COOLING TECHNOLOGIES IMPLEMENTED IN ESKOM

Power Station	Dry Cooling	Wet Cooling
Camden		X
Grootvlei *	X	X
Komati		X
Arnot		X
Hendrina		X
Matla		X
Kriel		X
Duvha		X
Tutuka		X
Lethabo		X
Kendal	X	
Majuba**	X	X
Matimba	X	
Medupi	X	
Kusile	X	

Notes:

1. * Grootvlei operates four wet cooled units and two dry cooled units. The dry-cooled units are currently not operational.
2. ** Majuba operates three units on a wet cooling system and three units on a dry cooling system

- All power stations also operate an auxiliary cooling system which is used to address the cooling requirements of equipment/systems supporting the main power generation, for example boiler/turbine pump cooling, oil coolers, bearing cooling, etc.
- Wet cooling systems (main and auxiliary) require chemical treatment to prevent scaling and corrosion in the cooling systems.
- Main cooling water systems are treated by means of clarification, lime treatment, desalination and/or acid treatment. The type of treatment used at the station impacts the water treatment expenditure of the station. Clarification and lime treatment comprises a significant portion due to the significant volume of chemicals used. Desalination is only applied for the treatment of cooling water at Tutuka, Lethabo, Grootvlei and Komati. Desalination has the highest treatment cost due to the number of chemicals dosed. The treatment with the lowest cost is acid treatment, where sulphuric acid is added directly into the cooling tower ponds. This treatment is applied when clarification and lime treatment is not installed or is not available.
- The warm cooling water is an ideal environment for microbiological growth which when formed on the heat exchanger surfaces, negatively affects the efficient transfer of heat across the media. Biocides, antiscalants and dispersants are chemicals that are routinely dosed into the wet cooling systems to reduce the microbiological activity in the system.

The main cost drivers for cooling water treatment are as follows:

- Change in raw water quality: The design of the cooling water treatment process is based on a specific raw water quality. A deterioration in the raw water quality compromises the efficiency of the treatment process which increases the treatment cost. Some of the stations have experienced a deterioration in the quality of the raw water.
- Raw water make-up to the cooling water system: The higher the make-up, the more salts enter the cooling water circuit, and the higher the water treatment cost. The make-up is influenced by water losses in the cooling water circuit.
- Deterioration in the availability, reliability and efficiency of the cooling water treatment plant: A decrease in the availability and reliability of cooling water treatment plants results in less water treatment taking place and less costs being incurred. A decrease in efficiency results in more chemicals being used, increasing the cost of treatment. The refurbishment of the cooling water treatment plants has been identified as a focus area. This is being addressed through the implementation of maintenance strategies at the stations. The cost of cooling water is expected to increase back to normal as the availability, reliability and efficiency of the cooling water treatment plants is restored.
- Recovery of drains, ash water, mine water or wastewater to the cooling water system: Depending on the quality of these streams, the recovery can increase or decrease the cost of cooling water treatment.
- Cost of chemicals used for cooling water treatment: Some stations experienced an increased cost in cooling water treatment due to issues with the procurement of chemicals. To address this, national contracts have been established for bulk chemicals, such as lime, and stations are putting in place long-term contracts for the other chemicals.
- Treatment for auxiliary cooling systems involves the dosing of chemicals to prevent microbiological growth, scale formation and corrosion.
- The leaks in the auxiliary cooling systems result in high chemical dosage at most sites, which increases the cost of auxiliary cooling water treatment. The causes of leaks have been identified and are being addressed.

8.3.1.5 Ash Water Treatment

- Ash is a waste product of all the coal fired power stations. The stations were designed with two different types of ashing systems: dry ashing and wet ashing.

- In a dry ashing system, the ash is transferred from the boilers to the ash disposal site on conveyor belts. This system requires no water treatment.
- In a wet ashing system, the ash from the boiler is mixed with water until it forms a slurry and then pumped to the ash dam. The ash settles in the dam and the water is returned to the station ash system to be reused for ash slurrying. The chemical properties of the water from the ash dam are such that they cause scale formation in the pipeline. To combat this, chemicals are dosed into the ash water return pipelines. Stations that operate wet ashing systems include Arnot, Camden, Duvha, Grootvlei, Hendrina, Komati, Kriel and Matla.
- The cost of ash water treatment is driven by the cost of the chemicals used for the treatment.

8.3.1.6 Sewage Treatment

- The stations are located in remote areas, a significant distance from municipalities. Therefore, all sites were designed with a sewage treatment plant to treat the sewage from the station ablution facilities, washrooms and kitchens.
- At sites that have a township that accommodates Eskom employees and their families, a separate sewage treatment plant is installed to receive and treat the sewage from the township residents / facilities.
- Most power stations have contracts in place to outsource the operation and maintenance of these plants. The cost of sewage treatment is also driven by the cost of the chemicals used for the treatment.

8.3.2 FY2025 Water Treatment costs

TABLE 21: SUMMARY OF WATER TREATMENT COSTS (RM)

Water Treatment (Rm)	Decision FY2025	Actual FY2025	Variance
Water Treatment	669	774	105

8.4 Sorbent Usage and Handling variance

TABLE 22: SORBENT USAGE VARIANCE (INCLUDING PRECOM) – RM

Sorbent Usage	Decision FY2025	Actual FY2025
Kusile (Rm)	311	149
Kusile (kt)	330	150

TABLE 23: SORBENT HANDLING COSTS (RM)

Sorbent Handling	Actual FY2025
Sorbent Handling	6.5

8.4.1 FY2025 Reasons for decision

NERSA did not make any adjustments to Eskom's application for sorbent costs or volumes.

8.4.2 Sorbent usage variance

The utilisation of sorbent is related to the quantum of energy produced at Kusile Power Station. Three units at Kusile Power Station were offline for most of the financial year because of a collapsed chimney. Because of this, the sorbent utilisation was lower than originally envisaged.

8.5 Start-up Gas and Oil costs

The NERSA MYPD5 Reasons for Decision did not apportion its decision per power station for start-up gas and oil costs. In the absence of such apportionment, the RCA motivation will be based on the prudency of actual expenditure

8.5.1 Main drivers of Fuel Oil Usage

FIGURE 2: FUEL OIL USAGE CATEGORIES

	Fuel Oil usage categories			
Routine Activities	***Unit startup/shutdown***	***Combustion support***	***Safety***	***Maintenance***
Abnormal Activities	- Extended unit light ups - Trip preventions - Fault finding after trip recovery - Forced shutdowns (e.g. boiler tube leak) - Post-outage defects require additional repairs	- Seasonal influence - Pre-certified coal qualities vary in batches - Combustion equipment is unreliable - Sootblowers are not used often enough - Instrumentation is unreliable - Production is prioritised and unit is kept on load	- Boiler combustion is governed by Fossil Fueled Firing Regulation (FFFR) - Operating units on manual increases risk - Panel controller must shut down unit when risk is high - Unit trips when protection operates	- Plant breakdowns - Some defects require unit shutdown - Online repairs increase trip risk - Defects increase as plant ages - Life cycle management projects are deferred due to funding

8.5.1.1 Routine fuel oil usage categories are summarised below

i. **Unit start-up and shutdown** – unit light ups can be cold, warm, or hot and depends on the amount of time that the unit was off load. A cold unit requires more warming to heat up the boiler (and consequentially more fuel oil usage) and turbine components than a warm or hot machine before coal combustion using mills can commence. Once the first coal mill is in service, the use of fuel oil will be reduced.

ii. **Combustion support** is required during normal plant operating activities such as sootblowing, mill changes and mill start-ups. Mills need to be heated up gradually to reduce the risk of thermally induced damage. Sootblowing is normally done at loads above 50% MCR and using fuel oil during sootblowing is sometimes necessary if there is a risk of a unit trip.

iii. **Safety** - the Fossil Fuel Firing Regulations (FFFR) require that fuel oil be used to maintain boiler temperatures when the coal flow is reduced, unevenly distributed or the air-to-fuel ratio is unsafe. This decision is based on the plant conditions. No accumulation of pulverised fuel (i.e. coal dust) may occur inside the boiler while the unit is in service as it can lead to an explosion or uncontrolled combustion.

iv. **Online routine maintenance** such as cleaning or repairing monitoring equipment and control instrumentation is required and fuel oil is used to support combustion as a precautionary measure during impulse line blow throughs and pyrometer cleaning.

v. Known risks such as coal contaminated by rocks during mining operations, occurs from time to time. High stone content in tube mills (i.e. not vertical spindle mills) reduces the efficiency and throughput of the mill. It is managed by grinding the stones during the off-peak periods and reducing the coal flow to the affected mill. The frequency of stone grinding varies according to the degree of coal contamination.

8.5.1.2 Abnormal plant activities

Abnormal plant activities which can increase the volume of fuel oil usage is impacted by the following:

i. **Unit start-up or shutdown:**

- **Extended unit light ups** – it sometimes happens that unit start-ups are longer than normal while root cause investigations into technical incidents are being conducted or while Operating and Maintenance personnel are returning plant to service which was repaired while the unit was off load.

- **Trip prevention** – risk mitigation is required when units operate with known risks such as boiler tube leaks or reduced coal qualities and need to run the unit long enough to be able to resolve the risk outside of the peak demand periods.
- There are occasions when the unit trip protection operates and results in a forced shutdown (e.g. boiler tube leak). The unit is designed to trip when a protection capability operates to ensure that costly catastrophic damage to the boiler, turbine or generator is avoided or minimised.
- **Post-outage defects** may arise if the repair was scoped incorrectly, or the quality of the repair was inadequate. The use of fuel oil arises when the repair is either performed with the unit still in service or it might need to be shut down and repaired offline.

ii. Combustion support

- Plant instability is experienced during transitions, such as increasing or decreasing load, due to fluctuating air and fuel supply, as well as flame instability. While there are several causes, the most common solution is to feed atomised fuel oil into the boiler to ensure more stable combustion conditions. This is collectively referred to as combustion support.
- Seasonal influences can impact the amount of fuel burnt because heavy rainfall can cause coal blockages at transfer points or cause conveyor belts to slip. Similarly, high ambient temperatures can cause cooling water systems to operate at values higher than their design range which can also cause units to trip when unsafe temperatures are reached.
- Stations and mining houses do not have blending facilities which results in pre-certified coal entering the station in batches. Batches of coal burn differently and may sometimes require fuel oil usage to prevent unit trips.
- Combustion equipment such as pumps, burners and heaters can sometimes be unreliable due to obsolescence, design deficiencies or incur breakdowns due to defects.
- There are occasions when routine sootblowing cannot be performed such as during periods of high demineralised water consumption or when the unit is constrained to operate at lower loads (e.g. when a trip risk exists at higher loads or there is a plant defect which results in high air-to-fuel ratios causing a loss of performance). If sootblowing is stopped for too long, the ash accumulation may eventually result in a unit trip or result in high boiler flue gas temperatures, which can cause damage to plant equipment downstream of the boiler.

- Instrumentation may become unreliable if not properly maintained. If the instrument malfunctions it could cause a trip, or the signal may drift, which could lead to a unit becoming unstable.
- If production is prioritised and the unit is constrained on load (e.g. operating unit with confirmed boiler tube leaks), it sometimes happens that the extent of the defect increases over time until eventually the equipment fails catastrophically, forcing the unit to shut down earlier than the planned outage date.
- Another risk which occurs is that there may be coal blockages (also referred to as "hangups") either in the common plant or the milling plant and fuel oil combustion support is used while the hangup is cleared. The hangup arises either due to a high percentage of fines content in the coal or high coal moisture (due to the geology where the coal is mined) or ambient rainfall. Mitigation plans are implemented as soon the risk is identified but addressing the root cause might sometimes take a while due to contractual and other considerations.

iii. Safety management

- Panel controllers are required to maintain safe boiler operating conditions through the selective use of fuel oil support to prevent trips during transient conditions. Should the unit be deemed to be too unsafe to stay on load, the operator is trained to initiate a controlled shutdown to mitigate the risk.
- Plant defects or instrument failures sometimes require that units be operated on manual. This requires the use of temporary operating instructions. Trip risks typically increase during these periods as operators cannot respond as quickly as automatic control systems.

iv. Maintenance

- Plant breakdowns sometimes occur between planned outages. Some of these breakdowns are due to normal wear and tear as the plant ages (e.g. fatigue, erosion, abrasion, etc.) but some breakdowns are due to excursions related to operating conditions (e.g. cycle chemistry, temperature or pressure).

v. Operating practices

- Staff shortages exist at most power stations and can result in routine planned maintenance and standby or running checks not being done. This negatively impacts the unit's reliability and efficiency over time.

8.5.2 Startup gas & fuel oil costs in FY2025

Start-up fuel oil is consumed while starting a generating unit after it has been shut down. This fuel oil is used to ensure stable boiler firing until pulverised coal from the mills can sustain combustion. Fuel oil is also used to stabilise combustion when a mill is run up to introduce additional pulverised fuel into the boiler while the unit load is gradually increased. The most significant fuel oil consumption occurs during cold start-ups.

Eskom reduced startup gas and fuel oil expenditure from R8.7bn in FY2024 to R7.5bn in FY2025. This improvement reflects fewer plant restarts and more stable operational patterns under the Generation Operational Recovery Plan. As the fleet operated more consistently, with an EAF improving to 60.9% and a reduction in loadshedding from 329 to 13 days, there were fewer cold and warm start-up events which require extensive oil firing.

TABLE 24: SUMMARY OF START-UP GAS AND OIL COSTS (RM)

Start-up Gas & Oil (Rm)	Decision FY2025	Actual FY2025	Variance
Start-up gas & oil	4 064	7 496	3 432

8.5.2.1 NERSA Decision vs Actual volumes (litres) and price (R/litre)

TABLE 25: NERSA DECISION VS ACTUAL VOLUMES (L)

Start-up Gas & Oil Consumption Volumes (L)	Decision FY2025	Actual FY2025
Start-up gas & oil	317 004 680	558 756 844

TABLE 26: NERSA DECISION VS ACTUAL AVERAGE PRICE (R/LITRE)

Start-up Gas & Oil Average R/Litre	Decision FY2025	Actual *Average* R/Litre FY2025
Start-up gas & oil	12.82	13.42

START-UP GAS & OIL AVERAGE PRICE VARIANCE CALCULATION

Price Variance	= *(Actual price - Decision price) x Actual litres*
	= R 333 122 662

The price of the start-up gas and oil is driven by the US Dollar oil price and the R/$ exchange rate. A significant variance in the price assumed in the decision and the actual price is illustrated in the table above.

START-UP GAS & OIL VOLUME VARIANCE CALCULATION

Volume Variance	= *(Actual litres - Decision litres) x Decision price*
	= R 3 099 262 742

START-UP GAS & OIL TOTAL VARIANCE CALCULATION

Total Variance	= *Price Variance + Volume Variance*
	= R 3 432 385 404

As noted from the price and volume variances quantified above, the RCA variance is largely driven by volumes being higher than what NERSA assumed in the determination. It should be noted that the circumstances for the resulting variances in FY2025 are similar to that approved by NERSA in the FY2023 RCA decision.

8.6 Nuclear Fuel costs

TABLE 27: VARIANCE IN NUCLEAR FUEL FY2024 (RM)

Nuclear (Rm)	Decision FY2025	Actual FY2025	Variance
Nuclear	1031	588	(443)

TABLE 28: REV 74, BASED ON CHANGE OF OUTAGE START DATES FOR OUTAGE 126 & 226 ONLY

FY	Unit 1 Outages Planned					Unit 1 Outages - Actual				
	Outage No.	Start Date	End Date	U1 Outage Length	Total Planned outage duration	Outage No.	Start Date	End Date	U1 Outage Length	Total outage duration
2023	126	08-Dec-22	31-Mar-23	113		126	10-Dec-22	31-Mar-23	111	
2024	126	01-Apr-23	12-Jun-23	72	185	126	01-Apr-23	18-Nov-23	231	342
2025	127	08-Jul-24	25-Nov-24	140	140	127	17-Feb-25	31-Mar-25	42	
2026	128	23-Mar-26	31-Mar-26	8		127*	01-Apr-25	30-Sept-25	182	224
2027	128	01-Apr-26	10-May-26	39	47					

FY	Unit 2 Outages Planned					Unit 2 Outages Actual				
	Outage No.	Start Date	End Date	U2 Outage Length	Total Planned outage duration	Outage No.	Start Date	End Date	U2 Outage Length	Total outage duration
2022	225	17-Jan-22	31-Mar-22	74		225	17-Jan-22	31-Mar-22	74	
2023	225	01-Apr-22	07-Aug-22	128		225	01-Apr-22	07-Aug-22	128	202
2024	226	30-Sept-23	31-Mar-24	183		226	11-Dec-23	31-Mar-24	183	
2025	226	01-Apr-24	03-Apr-24	2	185	226	01-Apr-24	30-Dec-24	2	384
2026	227	14-Apr-25	01-Sept-25	140	140	227	09-Nov-25	31-Mar-26	140	Dependent on U2 Licence extension
2027	228	18-Jan-27	07-Mar-27	48		228				TBD

The Primary Energy costs was based on a production plan 74 draft which had originally changed the start dates and durations of outage 126 and 226 for the Steam Generator Replacements (Originally planned to be replaced in Outage 125 and 225).

Changes in production plans were driven by the complexities and delays of installing Steam Generator replacements on both unit 1 and unit 2.

Due to significant delays in actual completion of both outage 126 & 226 in the prior two financial years the start dates of Outages planned for the 2025 financial year shifted out. Outage 226 started in December 2023 and was only completed in December 2024 due to various issues as a result of the Steam Generator Replacement modification.

The life extension on unit 1 was granted in July 2024 and due to the prior outage only being completed in November 2023 on unit 1, the fuel could still burn for additional months. The start date of outage 127 was then moved to 17 February 2025 instead of the original date planned of 08 July 2024 (which was original expected end of station life for unit 1).

TABLE 29: REASONS FOR VARIANCE IN NUCLEAR FUEL (RM)

Nuclear Primary Energy (Rm)	Application/ Decision FY2025	Actual FY2025	Variance	Explanations
Nuclear fuel other	103	6	(97)	see below
Nuclear Unit 1 usage	340	374	34	Unit 1 outage only started in February 2025 due to the life extension granted and delays in completing the prior unit outage
Nuclear Unit 2 usage	483	123	(359)	Unit 2 outage duration exceeded the original budget. Production plan at the time of application estimated 185-day outage duration. The actual outage duration was 384 days; resulting in lower fuel burn
Nuclear Spent Fuel	105	85	(20)	Favourable Variance: Unit 1 life extension granted in July 2024 for unit 1. Due to delays in completing outage 226, Spent fuel asset for 226 only capitalised in November 2024 (planned in prior financial year) and Outage 127 only started in February 2025. Spent fuel asset will only be capitalised in next financial year; resulting in lower amortisation
Total Nuclear Primary Energy	**1031**	**588**	**(443)**	

TABLE 30: NUCLEAR FUEL OTHER (RM)

Nuclear Fuel Other (Rm)	Application/ Decision FY2025	Actual FY2025	Variance	Explanations
Fuel Write off – Outage226	38	0	(38)	Outage 226 Nuclear Fuel write off budgeted for not incurred, it is highly likely that the fuel discharge will be used again as burn rate was below threshold for write off
Fuel Write off - Outage127	51	0	(51)	Due to delays experienced in both outage 126 & 226; together with the extension of life granted for unit 1. Outage 127 only started in February 2025. Fuel write-off to take place in next financial year
Ad hoc Fuel Studies	12	4	(8)	Minimal ad hoc fuel studies incurred for the financial year
Fuel Studies amortisation	2	2	0	
Total Nuclear fuel other	**103**	**6**	**(97)**	

9 Demand Response and Power Alerts

9.1 Demand Response

9.1.1 Demand Response Actuals vs NERSA decision

Demand Response provides the System Operator with key levers, namely, instantaneous, and supplemental products to meet the daily system operating reserve margins. The actuals for FY2025 vs the decision is outlined in the table below.

TABLE 31: BREAKDOWN OF DEMAND RESPONSE AND POWER ALERT (RM)

DR and Power Alert (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Instantaneous	No Breakdown	19	-	-	-
Supplemental		69	-	-	-
Programme admin costs		34	-	-	-
Total Demand response	**416**	**122**	**(294)**	**-**	**(294)**
Power alert	43	34	(9)	-	(9)
Total programme costs	**459**	**156**	**(303)**	**-**	**(303)**

- The Methodology imposes a penalty when the target is not achieved and no reward for exceeding the target. Programme administration costs are not included in the formula to calculate the penalty.
- These administration costs are assessed in terms of paragraph 17.1.1.4 of the MYPD Methodology which states that the adjustment for prudently incurred over or under-expenditure on operating costs as may be determined by the Energy Regulator will be allowed.

9.1.2 Reason for the Demand Response Actuals for FY2025

NERSA has determined R416m revenue related to Demand Response (DR) in FY2025. The actual expenditure for this year was R122m. The reason for the variance is due to economic conditions and commodity price fluctuations which resulted in many of the participating load providers not being available to be dispatched. Furthermore, the contracting of Negotiated Pricing Agreements (NPAs), which has a built-in demand response mechanism has impacted the spend as it has a zero-cost implication on the Demand Response budget. It must be noted that the DR expenditure is a function of usage (the lower the usage, the lower the expenditure).

DR is catered for in the daily operating reserves of the SO (even during times of surplus capacity) as part of normal system operations and is dispatched only when needed. DR is crucial in ensuring security of supply for any system. DR is an appropriate lever as it’s used over short periods; allows the customer the flexibility to make up production at different times of the day; and comes in at a lower cost than running open cycle gas turbines

9.2 Power Alert

9.2.1 Power Alert Actuals vs NERSA decision

The Power Alert system is a real-time system using television broadcasts during evening peak periods (17:00 to 21:00) to inform the South African public about the status of the electricity network. These alerts are colour-coded messages, indicating the four stages in electricity status levels (green, orange, red and black). More importantly, the alerts are supported with information about the actions required from the target audience to reduce their electricity consumption, address the constrained situation, and avoid or limit the stages and duration of loadshedding. The Power Alert television broadcasts from April 2024 to February 2025 had an average of 248 alerts, reaching approximately 18.8 million viewers monthly, playing a critical role in keeping the public informed and providing daily system updates. The actuals for FY2025 vs the NERSA decision are outlined in the table below.

TABLE 32: BREAKDOWN OF POWER ALERT (RM)

Power Alert (Rm)	Decision FY2025	Actual FY2025	RCA FY2025
Total Power Alert	43	34	(9)

9.3 Reason for the Power Alert Actuals for FY2025

NERSA determined R43m revenue related to Power Alert in FY2025. The actual expenditure for this year was R34m. The variance is because effective media negotiations achieved an average discount of 51% on media placements to broadcast the Power Alerts on all relevant television stations, namely SABC, DStv, ETV and OVHD. This still ensured the best possible reach across all the electricity users in South Africa lower, middle and higher-income users ensuring that the public is well informed and requesting them to assist in reducing the strain on the national grid.

10 Open Cycle Gas Turbines (OCGTs)

10.1 Regulatory Context

The MYPD Methodology states the following:

> 12.3.1 Gas turbines are provided to operate during peak periods as well as emergency situations. Subject to the conditions set out in this Methodology, gas turbine generation cost will be allowed as a full pass-through cost, but limited to volumes allowed by the Energy Regulator, except where such use was necessary to ensure security of supply due to events outside of management control.
>
> 12.3.2 Capacity constraints shall be mitigated by gas turbine generation as a last resort. For avoidance of doubt, gas turbine generation should be employed before implementation of loadshedding activities.

The usage and cost of open-cycle gas turbines (OCGTs) are treated as pass-through costs under the MYPD Methodology, subject to a prudency review of volumes. The methodology stipulates that OCGTs are to be operated as a last resort to ensure security of supply and before the implementation of load shedding. Eskom's OCGT usage remained above the MYPD5 Decision assumptions but was essential in maintaining system stability and minimising load shedding.

10.2 Use of OCGTs

OCGTs are a supply option which can respond to dispatch instructions at the fastest rate while sustaining flexible operation over extended periods. They also play a crucial role in terms of system reliability and system resilience. It is of utmost importance that the system always carries some level of quick response and flexibility to respond to unforeseen circumstances.

These may include sudden increase in demand due to weather conditions, coinciding with unit trips in one day or week which may put the system at risk. These circumstances may occur even in the instances of higher plant availability periods and result in utilising the OCGTs as the quick response mechanism.

Due to the increase in self-dispatching capacity such as wind and solar PV, the "duck curve" is expected to become increasingly evident. This will require additional flexibility of the fleet. Thus, it's important to note that Eskom will continue to utilise diesel strategically and prudently, with OCGTs forming an integral part of the generation fleet.

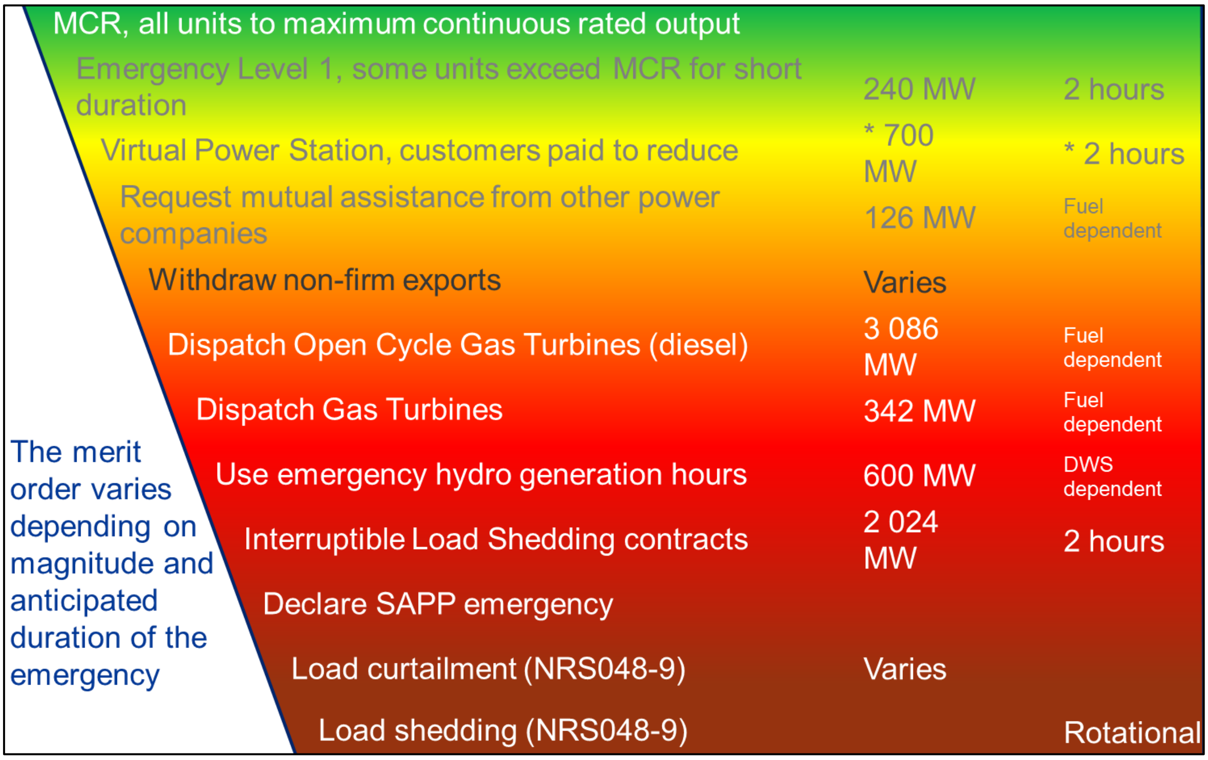
10.3 OCGT Dispatch and System Operator Role

Although the aim is to minimise the utilisation of OCGTs, peaking capacity is designed precisely to provide power to manage the peak demand and emergencies and will be utilised as such. With the penetration of renewable energy, it becomes even more important to manage the peaks and valleys in demand that the power system experiences daily. Avoiding the use of OCGTs is not necessarily the cheapest way to run the power system. Peaking power, although expensive, can offset mid-merit and base-load power that is not needed to run 24/7. Loadshedding remains an essential tool for the System Operator to protect the grid. Although there has been a significant improvement in generation performance, intermittent loadshedding may still be required should a significant event occur on the power system.

During FY2025, Eskom's generation performance improved with the EAF rising from 54.6% in FY2024 to 60.9%, and load shedding days decreasing from 329 to 13, substantially reduced dependence on OCGTs compared to prior years. However, strategic dispatch of OCGTs, both Eskom-owned and IPP OCGTs, continued to play a critical balancing role.

Eskom's System Operator dispatched these units in accordance with the Grid Code and MYPD Methodology, confirming that OCGTs were used only when necessary to maintain security of supply.

FIGURE 3: THE SYSTEM OPERATOR MERIT ORDER FOR EMERGENCY RESOURCES



It should be noted that the use of OCGTs is before loadshedding and curtailment.

The details of how Eskom System Operator utilised the OCGTs before loadshedding is illustrated in the revenue variance section of this document, that addressed the loadshedding volumes.

10.4 OCGT Fuel Usage and Cost in FY2025

In FY2025, Eskom's Gross OCGT fuel costs amounted to R13.3bn the makeup of which is reflected in the table below, represents a significant reduction from the Gross R26.6bn in FY2024. This decline reflects both lower OCGT operating hours and the successful implementation of the Generation Operational Recovery Plan, which improved base-load station reliability. OCGT energy sent out for FY2025 was 2.2 TWh, down from 3.6 TWh in FY2024.

TABLE 33: SUMMARY OF OCGT FUEL COSTS (RM)

OCGT cost (Rm)	Decision FY2025	Actuals FY2025	Variance
Open Cycle Gas Turbine fuel cost	-	**13 165**	-
Ankerlig	-	6 819	-
Gourikwa	-	6 274	-
Acacia	-	36	-
Port Rex	-	36	-
OCGT fuel storage and demurrage	-	**151**	-
Ankerlig	-	132	-
Gourikwa	-	19	-
Gross OCGT cost	**8 862**	**13 316**	**4 454**
OCGT fuel rebate (SARS)	-	**(14 195)**	-
Ankerlig	-	(6 684)	-
Gourikwa	-	(6 967)	-
Peaking - Durbanville	-	(544)	-
Total OCGT Cost	**8 862**	**(879)**	**(9 741)**
RCA Adjustment	-	*8 741*	-
Total OCGT Cost for RCA purposes	**8 862**	**7 862**	**(1 000)**

10.4.1 OCGT Refund

10.4.1.1 Background to SARS rebate

Eskom uses diesel as fuel in its OCGT plants. The diesel price includes certain levies. The South African Revenue Services (SARS) provides diesel fuel levy refunds and rebates for electricity generation. Eskom is registered for the refund of fuel levy and Road Accident Fund Levy (i.e. "diesel refunds) upon distillate fuel used solely in the electricity generation plants known as Ankerlig Power Station and Gourikwa Power Station. This is in terms of the provisions of the Customs and Excise Act, 1964 (the "Customs and Excise Act") including Schedule 6 thereto.

Eskom is required to pay the full price (including levies) to the supplier. Claims for refunds of the levies are then made to SARS. Meter reading and recordkeeping requirements need to be complied with. Prior to 2019, Eskom claimed and received the refunds, in accordance with the legislation.

However, from February 2019 to August 2024, concerns were raised by SARS on Eskom not complying with certain aspects of Customs and Excise Act. This included calibration of flow meters and recordkeeping. This resulted in Eskom not receiving the refunds for that period. Eskom disputed SARS's findings, lodged appeals against SARS's findings and applied for the alternative dispute resolution process. Eventually, Eskom and SARS settled the issues in dispute. The Settlement Agreement provided for a settlement amount of R9bn for the periods February 2019 to August 2024 and a record keeping arrangement for the periods from September 2024. The settlement was for 80% of the eligible refund. The R9bn refund is in for the total utilisation of diesel from Ankerlig and Gourikwa Power stations for the period February 2019 to August 2024.

10.4.1.2 Reconciliation of fuel refund

NERSA has determined the level of prudent utilisation of OCGT power stations and thus the quantity of diesel fuel utilised. This will be done for subsequent years where RCA decisions are yet to be made.

Since the refund was received during FY2025, regulatory reconciliation was undertaken. It is ensured that correct allocations are made to both the consumer and Eskom. Thus, to ensure historical matters are also considered, the NERSA OCGT decision of FY2025 addresses the refunds for previous years.

10.4.1.2.1 FY2019 TO FY2021

From a regulatory point of view, when the Eskom revenue applications were made for FY2019, 2020 and 2021 – the OCGT costs in the application (and thus decision) were net of the refunds. Thus, it was assumed at that stage that Eskom will be in a position to receive the refunds related to the levies. However, it is known that this was not the case. Thus, any rebate for FY2019, 2020 and 2021 has already been accounted for from a regulatory point of view. For completeness, it needs to be pointed out that an 80% settlement was reached and refunded to Eskom. The NERSA decision, however, assumed Eskom gets the 100% rebate This additional benefit to consumers is not tampered with.

10.4.1.2.2 FY2022

The RCA application was made at a gross level when considering the rebate i.e. the OCGT cost claimed for in the RCA was the amount before the deduction of any rebates. This was done due to the dispute with SARS on the recovery of the rebates; hence it was assumed that there was a risk of not recovering the rebates from SARS. For purposes of the refund allocation, the original revenue decision as well as the RCA decision is taken into account. Since the actual OCGT fuel utilisation was significantly more than the decisions, none of the refund in respect of FY2022 is included in this RCA application for the benefit of the consumer.

10.4.1.2.3 FY2023

The revenue application and RCA application were made at a gross level when considering the rebate i.e. the OCGT cost claimed for in the RCA was the amount before the deduction of any rebates. This was done due to the dispute with SARS on the recovery of the rebates; hence it was assumed that there was a risk of not recovering the rebate. For purposes of the refund allocation, the original revenue decision as well as the RCA decision is considered. Since 100% of the actual OCGT fuel utilisation was allowed by NERSA, the entire refund received from SARS for FY2023 is included in this RCA application for the benefit of the consumer.

10.4.1.2.4 FY2024

The revenue application and RCA application were made at a gross level when considering the rebate. This was done due to the dispute with SARS on the recovery of the rebates; hence it was assumed that there was a risk of not recovering the rebate. For purposes of the refund allocation, the original revenue decision as well as the RCA decision is considered. Since the actual OCGT fuel utilisation was significantly more than the revenue decision, none of the refund is included in this RCA application for the benefit of the consumer. It needs to be noted that the RCA decision is yet to be made. In the event that the regulatory treatment is the same as for FY2023, then further reconciliation will be undertaken in a subsequent RCA submission after the FY2024 RCA decision is made.

10.4.1.2.5 FY2025

The FY2025 RCA application addresses the refunds that need to be reconciled from FY2019. The actual diesel costs are reduced by the historical refund adjustments. This specifically refers to the RCA adjustment for the benefit of the consumer related to FY2023.

In addition, we add back the amount that was deducted from the OCGT actual cost in FY2025 in respect to the provision that was reversed.

The result of the above, when comparing the actual OCGT fuel costs with the revenue decision for FY2025, is a variance of R1bn in favour of consumers. This is illustrated in the table above.

The table below reflects the OCGT production per station.

TABLE 34: OCGT PRODUCTION PER STATION (GWH)

OCGT production (GWh)	Decision FY2025	Actual FY2025	Variance
Ankerlig	No breakdown	1 125	No breakdown
Gourikwa		1 041	
Acacia		5	
Port Rex		5	
Total GWh	**1 266**	**2 176**	**2 176**

OCGT Fuel burn in litres is outlined in the table below

TABLE 35: OCGT FUEL BURN (LITRES)

OCGT Fuel burn (litres)	Decision FY2025	Actual FY2025	Variance
Ankerlig	No decision	352 613 892	No decision
Gourikwa		322 799 558	
Acacia		1 860 340	
Port Rex		1 775 393	
Total Litres		**679 049 183**	

The following table outlines the OCGT fuel cost in R/Litres

TABLE 36: OCGT FUEL COST R/LITRE

OCGT Fuel burn (R/Litre) excluding rebate and storage	Actuals FY2025
Ankerlig	19.34
Gourikwa	19.43
Acacia	19.33
Port Rex	20.11
Average R/Litre	**19.39**

10.5 Observations

It is submitted that Eskom System Operator has dispatched OCGTs in accordance with the NERSA MYPD methodology. The variances between the assumptions in the decision and actuals for FY2025 illustrate the need for the use of OCGTs, both Eskom and IPP OCGTs, to the extent required to minimise the impact of loadshedding on the South African economy. The overall economic impact of loadshedding has thus been minimised. Considering the above and that the requirement for OCGT use of this level was primarily due to reduced IPP production (outside of Eskom's control) and lower than NERSA assumed Eskom fleet EAF (the context of which should be taken into account), and that NERSA has considered the IPP OCGT usage prudent and efficient.

11 Independent Power Producers (IPPs)

NTCSA acknowledges the role that IPPs play in the South African electricity market and remains committed to facilitating the entry of IPPs, to strengthen the system adequacy and meet the growing power demand. NTCSA has procured a combination of short-, medium- and long-term supply from IPPs.

11.1 Legal basis for IPPs per the MYPD Methodology

All the IPP Power Purchase Agreements (PPA) entered were approved as part of the licensing process by NERSA prior to being finalised and signed.

11.2 Allowed vs Actual IPP costs for FY2025

The NERSA determination with regards to revenue related to IPP costs for FY2025 in the MYPD 5 decision was R76 970m. Total IPP cost for the FY2025 RCA is R47 273m, including the capacity payment for the DOE Peakers (which is capitalised as a lease payment for financial reporting purposes). A summary of the costs and volumes from IPPs are presented in the table below.

A summary of the costs and volumes from IPPs are presented in the table below:

TABLE 37: IPP COSTS (RM) AND VOLUMES (GWH)

IPP cost & volume	Cost (Rm)			Volumes (GWh)			Average costs (Rm)		
	FY2025								
	Decision	Actual	Variance	Decision	Actual	Variance	Decision	Actual	Variance
Renewable IPP Programme	46 363	38 128	(8 235)	24 907	17 420	(7 487)	1 861	2 189	327
Risk Mitigation	10 234	2 078	(8 156)	5 054	859	(4 195)	2 025	2 419	394
DoE Peaker	10 510	6 005	(4 505)	1 056	662	(394)	9 950	9 071	(879)
Storage	2 004		(2 004)	(85)	-	85			
Emergency Generation Programme	5 757	1 062	(4 695)	3 364	425	(2 939)	1 711	2 499	787
Standard Offer Programme	1 778	-	(1 778)	2 628	-	(2 628)	677	-	(677)
Total IPP's	**76 647**	**47 273**	**(29 374)**	**36 924**	**19 366**	**(17 558)**	**2 076**	**2 441**	**365**
Network pass-through	323	-	(323)	-	-	-	-	-	-
Total IPP's	**76 970**	**47 273**	**(29 697)**	**36 924**	**19 366**	**(17 558)**	**2 085**	**2 441**	**357**
Less: current year provisions raised			(160)						
Add: Reversal of prior provisions			3						
Total IPP cost for RCA			**(29 853)**						

11.3 Reasons for IPP variances in FY2025

The System Operator utilised 17 558 GWh less energy from IPPs when compared to the decision during FY2025. The average costs for IPPs were higher at R2 441/MWh against the decision of R2 085/MWh. The expenditure on IPPs was R29 697m lower than the decision (excluding adjustments for provisions).

11.3.1 Renewable IPPs

- **Price variance:** The renewable IPP average price was R327/MWh more than the NERSA determination due to delays in the commercial operation of Bid Window 5 which are significantly cheaper than prior bid windows.

- **Volume variance:** The volumes produced by REIPP generators were significantly lower (by 7 488 GWh) than that assumed in the NERSA determination due to project delays and project not reaching financial close under Bid Window 5. As discussed in the production planning section, Eskom's generators were required to accommodate the shortfall of energy created by the IPPs not providing energy in accordance with the NERSA determination.

11.3.2 Deemed Energy payments

Deemed energy payments of R225.1m for FY2025 were made for:

- Curtailment events (R224.9m), and

- Exceedance of the Allowed Grid Unavailability Period in municipal networks (R0.14m).

Forty-nine curtailment events occurred during the financial year. The curtailment of REIPPP projects is a prudent response to the system risk where thermal generators are severely constrained from ramping down further (due to operating at or near the minimum stable generation level) and demand continues to require lower generation. The alternative of de-committing a thermal generating unit is more costly as it would incur start-up costs in re-starting as well as introduce risk of not being available to meet peak demand (with concomitant risk of higher diesel utilisation).

The Allowed Grid Unavailability Period (AGUP) in the Renewable IPP Power Purchase Agreements (PPAs) provides for a maximum number of hours in each contract year during which the network may be unavailable before the IPP may claim deemed energy provisions. Two of the Johannesburg Landfill Gas sites are within the City Power network, and one solar site is in the Dawid Kruiper Municipality. These sites are subject to load shedding by the municipality. The deemed energy payments during FY2025 arose due to AGUP exceedance in the prior year.

11.3.3 Use of System (UoS) charges

The use-of-system charges incurred by IPPs are treated as pass-through costs to the Buyer under the PPA, amounting to R415m. This principle has been addressed in the High Court judgements of the review of the NERSA FY2019 revenue decision as well as the review of the NERSA RCA decisions for FY2015 to FY2017.

11.3.4 DOE Peaker

- **Price variance:** The payment to the Peaker is split between capacity payments and energy payments as it is fully dispatched by Eskom.
- **Volume variance:** The reduced utilisation of diesel generation during the year arose from improved performance by the Eskom generation fleet and thus a lower requirement from diesel generation.

11.3.5 Eskom short term programmes

- **Price variance:** The prices under the Emergency Generation Programme (EGP) were higher than originally assumed due to more expensive generation being included under the EGP.
- **Volume variance:** Eskom was unable to encourage as much uptake in the EGP as had been expected at the time of the decision and none of the Standard Offer projects operated during the financial year.

12 International purchases

12.1 International purchases variance

Eskom acquired 7 570 GWh of electricity from neighbouring countries that resulted in purchases of R6 540m which generated energy inflows during the year. The details of the variance between the actuals and the decision are outlined in the table below.

TABLE 38: INTERNATIONAL PURCHASES (RM)

International Purchases (Rm)	Decision FY2025	Actual FY2025	Variance
International Purchases	9 334	6 540	(2 794)

12.2 Cross-border purchases of electricity

The majority of cross–border purchases are from Hidroelectrica de Cahora Bassa (HCB), hydro electrical plant in Mozambique. During FY2025, HCB improved on its historical trend as assumed in the MYPD application. When HCB performs better than their Contractual Maximum Demand (CMD) of 1 150MW consistently, higher volumes are purchased, at a lower rate than in the application, and resulting in a lower overall cost to the contract. Due to delays in finalising the reset of the tariff, the previous rates were applicable. It is likely that once the rates have been finalised, the adjustment would need to be retrospectively applied.

Additionally, Eskom purchased marginal volumes from Lesotho Electricity Company (in terms of its power purchase agreement) and Southern African Power Pool competitive markets (in terms of the SAPP arrangements). These purchases assisted to alleviate the effects of load shedding.

13 Environmental levy

13.1 Allowed vs Actual Environmental levy costs for FY2025

TABLE 39: ENVIRONMENTAL LEVY COST CALCULATION OF RCA BALANCE (RM)

Environmental Levy	Decision FY2025	Actuals FY2025	Variance
Non-Renewable energy sent out	171 251	190 011	18 760
Add: Auxiliary volumes	14 569	17 703	3 134
Generating Volumes	**185 820**	**207 637**	**21 894**
Rate in c/kWh	3.5	3.5	-
Generation Environmental Levy Cost	**6 503**	**7 270**	**767**

The MYPD methodology allows for variances to be adjusted through the RCA mechanism as reflected in section 16 of the MYPD methodology. The variance in environmental levy is due to the energy generated from the relevant power stations being lower than that determined by NERSA in its decision.

16. Taxes and Levies (not income taxes)
16.1 The Government imposes certain taxes and levies that are payable by Eskom.
16.2 Levies are any charges that the Government may impose and payable by Eskom arising from its licensed activity.
16.3 Taxes are any amount arising from an enacted legislation that the Government may require Eskom to pay which amount will be calculated in terms of such legislation.
16.4 Principles regarding taxes and levies
16.4.1 The taxes and levies are exogenous and will be treated as a pass-through cost in the MYPD.
16.4.2 Taxes and levies will be treated as a separate account in the Eskom revenue determination.
16.4.3 Eskom must ensure that the cost of the taxes and levies is specified and that the calculation thereof is clear and concise.
16.4.4 The amount provided for the taxes and levies must be ring-fenced and any over or under-recovery will be recorded in the RCA.

13.2 Environmental levy cost dynamics

The decisions whether to dispatch particular power stations (whether in planning or actual mode) are driven by factors other than the Levy cost. The dispatch is based on a least cost philosophy meaning that a Power Station with lower cost of production would be dispatched before a Station with a higher cost of production. Given that the various stations' fuel cost per unit of output reflect differences which are greater than the Levy rate, it could result in Stations with higher Aux % (and thus higher Levy cost) being planned to run harder, hence increasing the levy cost above its theoretical minimum whilst still reducing the overall total cost of production.

In addition, in actual mode the System Operator currently has limited flexibility in dispatch due to low reserve margins, thus day-to-day system dynamics could easily cause actual plant mix differing from originally estimated plant mix.

14 Regulatory Asset Base

14.1 Regulatory Asset Base (RAB) related RCA variance

The variance in the RAB from the NERSA decision to the actuals impacts the revenue related to depreciation and return on assets (ROA). In accordance with the decision, various categories of the RAB are considered. The variance in the RAB value in each of the six categories at an Eskom level are reflected in the table below.

14.2 RAB and ROA variance

The RCA balance application is in respect of return on assets as shown in the table below.

TABLE 40: RAB AND RETURN ON ASSETS VARIANCE (RM)

RAB and RoA	Decision FY2025	Actuals FY2025	Variance
Depreciated Replacement Costs (DRC)	801 373	820 245	18 873
Completed assets post valuation	42 748	187 363	144 615
Asset purchases	521	3 620	3 100
Work Under Construction (WUC)	50 647	73 000	22 353
Working capital	69 057	73 849	4 792
Assets funded by customers upfront	(14 791)	(12 165)	2 626
Closing RAB values	**949 554**	**1 145 913**	**196 359**
Average RAB	988 345	1 086 524	98 180
Percentage Return on Assets	1.58%	1.58%	
Return	**15 616**	**17 167**	**1 551**

The R195bn variance in RAB is due mainly to significant differences in completed assets post valuation of R144bn and WUC of R21bn, because of the incorrect implementation of the MYPD methodology as well the High Court order of 24 October 2022. NERSA erroneously disallowed the opening balances in these asset categories. The impact of the incorrect RAB valuation results in a variance of R1 544m related to ROA. A variance in the commissioning of Eskom's NTCSA and Distribution capital projects, when compared to application, was observed.

14.3 Depreciation

The depreciation variance is shown in the table below. Although NERSA disallowed the RAB in its decision for the transfer to commercial operation and WUC categories, it did not make concomitant adjustments to the depreciation determination. Thus, a misalignment exists. The depreciation allowed in the determination was very close to the depreciation applied for. However, the value of the RAB was significantly different from the Eskom application. A variance in the commissioning of Eskom's NTCSA and Distribution capital projects, when compared to application, was observed.

TABLE 41: DEPRECIATION VARIANCE (RM)

Depreciation	Decision FY2025	Actuals FY2025	Variance
Fixed assets - DRC Values	55 208	56 012	804
Fixed assets - Transfers to CO	18 192	11 285	(6 907)
New Investments (Asset purchases)	484	905	421
Assets funded by customers upfront	(840)	(944)	(104)
Total GTD	**73 044**	**67 257**	**(5 787)**
Corporate Depreciation	332	0 *	(332)
Total Depreciation	**73 376**	**67 257**	**(6 119)**

Note: * Corporate Depreciation is included in Corporate OPEX

14.4 Transfer to commercial operations

The variance in the transfer to CO is mainly due to transmission transfers being significantly lower than the decision. This difference explains the variance in the depreciation as seen in the table above.

TABLE 42: TRANSFER TO COMMERCIAL OPERATIONS (CO) – RM

Transfer to Commercial Operation (CO)	Decision FY2025	Actuals FY2025	Variance
Generation	44 482	48 697	4 215
Transmission	9 873	705	(9 168)
Distribution	6 586	5 283	(1 302)
Assets funded upfront by Customers	(926)	(1 565)	(639)
Transfers to Commercial Operations	**60 015**	**53 121**	**(6 894)**

15 Eskom Capital Expenditure

15.1 Generation Capital Expenditure

The long-life capital nature of the electricity industry requires significant focus on build, restoration and replacement of assets for the functioning and reliability of the industry to provide the service of delivering electricity. In the application window, Generation-related capital expenditure plans focused on delivering the following projects:

- Generation new build programme- commercial operation of remaining unit of Kusile and completion of all outstanding new build scope and defects;
- Generation technical plan capital expenditure to sustain existing plant;
- Generation invested in Cost-Plus mines which will provide Generation with a more sustainable source of coal. This is included as future fuel;
- Generation also invested in projects to reduce particulate emissions and water consumption, on the journey towards environmental compliance;

TABLE 43: ESKOM CAPITAL ALLOCATION PRINCIPLES & GUIDELINES

Guiding questions	Category	Definition	Considerations[1]	Prioritisation
Is there legislation/ permit/license need for the project?	Mandatory	• Safety projects that if not addressed could lead to significant incidents/harm to employees and general public • Immediate and palpable risk of regulatory or legal breach • Compliance/ Statutory/Grid code that if not addressed could lead to significant incidents, losses, reputational damage and legal implications • No or limited discretion on timing or options	❑ Project critical to mitigate risks to people safety ❑ Essential to meet regulatory and statutory plant safety requirements ❑ Essential to meet environmental compliance requirements ❑ Project aimed to protect and safeguard key assets/plant	High priority
Is there an internal policy or guideline driving the project ?	Sustaining	• Projects to maintain current assets for operational sustainability, that poses no significant interruptions to current operations and have a high confidence of execution. • Projects that allow for the organisation to 'stay in business' and deliver on their mandate in line with policy	❑ Critical for continued delivery against shareholder expectation and mandate ❑ Critical maintenance intervals have been reached and cannot be deferred. ❑ Projects that aim to replace obsolete plant and equipment which are at risk of leading to significant failure/ loss of revenue/impact on production	Increasing discretion
Can this project be financially justified?	Strategic	• Projects to enable growth for the business and allow for additional revenue generation and enable the achievement of strategic objectives. • These projects are important but not critical and can considered for future commercial and financial sustainability	❑ Growth projects that have superior financial returns(NPV>0, IRR>WACC) ❑ Projects that enable strategic goals in both the short term and medium/long term ❑ Projects that increase capacity ❑ Projects that increase revenue/ decrease cost	
	Betterment	• Projects to enable asset efficiency improvements/cost reduction for operational sustainability	❑ Operational efficiency and productivity improvements ❑ Performance enhancement beyond original design standards	Low priority

1. Ability to execute and risk assessments considered for each category

15.2 Generation Capex for FY2025

TABLE 44: SUMMARY OF GENERATION CAPEX FOR FY2025 (RM)

Generation Capex (Rm)	Application FY2025	Decision FY2025	Actuals FY2025	Variance
New Build and Major Projects	14019	14019	5840	(8179)
Outage Capex	9349	9349	10037	688
Tech Plan Capex	8708	8708	5978	(2730)
Renewables Capex	61	61	0	(61)
Land and Rights	0	0	0	0
Other	0	0	3320	3320
Total Capex WUC	**32137**	**32137**	**25176**	**(6961)**
Nuclear future fuel	1426	0	1485	1485
Coal and water future fuel	2349	0	1527	1527
Asset Purchases	214	0	1508	1508
Total Generation Capex	**36126**	**32137**	**29694**	**(2443)**

The MYPD Methodology provides for the recovery of capital-related costs over the useful life of the asset through Return on Assets (RoA) and depreciation. Capital expenditure is not directly included in the allowed revenue formula, but rather capitalised and recovered over time.

15.2.1 New Build and major capital projects

The mandate of Eskom is the effective execution of capital projects in support of reliability and security of power generation and supply to foster economic growth and social prosperity.

Eskom continues to execute the major projects which are Medupi and Kusile as well as Generation coal and clean technology projects which includes refurbishment projects as well Emissions projects.

15.2.2 Outage and Technical Plan Capex

Outage and technical plan capex is critical to sustain the reliability of the power stations in the medium to long term. In the FY2023 RCA decision NERSA correctly included RAB related to outage capital for the recovery of return on assets and depreciation. This illustrates that it is not of an operational nature.

Considering the severely constrained system (capacity and financial), Eskom cannot execute all the outages required to significantly improve the plant condition and thus, performance. Eskom utilises a capacity planning process that optimises the planned outages on a continual basis, based on the prevailing constraints and outage priority.

- The capacity planning process requires, as its main input, the long-range demand forecast less the forecasted renewables contribution (residual demand). This is the demand expected to be supplied by Eskom and the OCGT IPP's. The daily peak demand is then used for capacity planning.

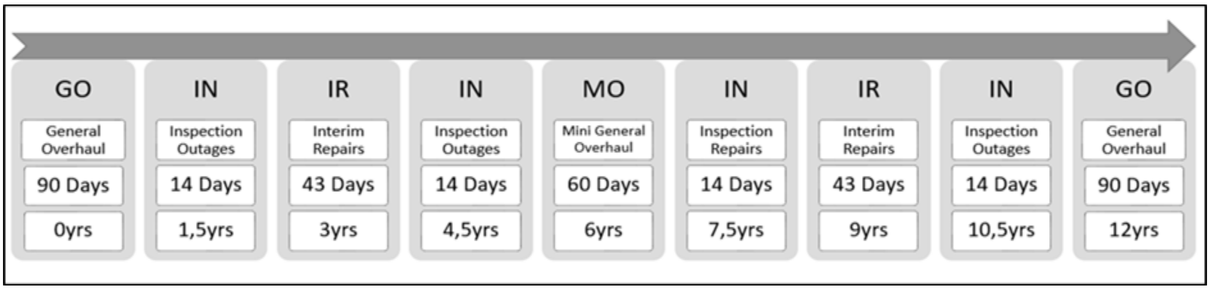
- The next important assumption for planning purposes is predicting the expected UCLF of the fleet.

- In addition to the load forecast and expected UCLF an additional 2 200 MW of reserve margin is catered for. The total available capacity (~ 47 000 MW) less the sum of the load forecast, expected UCLF and reserve margin determines the available outage capacity per day. Outages are then slotted into these spaces and optimised **to minimise the capacity shortfall (i.e., to reduce or minimise the risk of load shedding)**.

- Planned outages within the Generation fleet are grouped into categories namely, mandatory, sustaining, strategic and betterment and are ranked higher for **capital funding allocation and scheduling**. *Mandatory outages have the possibility for serious damage to plant if not executed and cannot be moved without a risk assessment being performed*. Sustaining, strategic and betterment outages affect plant performance and reliability without resulting in major damage or safety of personnel. **The scheduling of these is more flexible and used to balance the risk of increasing stages of loadshedding**.

- Each station has an outage philosophy which includes outages with varying scope and duration within the philosophy cycle (e.g. – 12 years). The Figure below illustrates the outage philosophy cycle of Tutuka power station. Maintaining the philosophy outage cycle is critical to ensuring reliability. Not all outages required as per philosophy are able to be scheduled on time due to the need to manage capacity constraints (risk and extent of loadshedding) or preparedness levels.

FIGURE 4: TUTUKA OUTAGE PHILOSOPHY CYCLE



- All statutory maintenance required in the 12-month planning period is accommodated in the plan. Due to the capacity constraints this leaves little or no room to move, extend, add outages, accommodate outage delays, or major incidents/events. Outage delays on certain large plants can result in significant pressure on the system and ultimately present a risk of higher levels of loadshedding.

- Short-term weekend-opportunity maintenance is scheduled weekly based on the available capacity due to lower demand. Weekend opportunities are mainly granted to address emergent risks to production.
- Peak demand profile is highest in winter with the lowest being in summer. This profile results in less space being available in winter for outages and increased space in summer as the demand reduces.

Mandatory outages affect plant and personnel safety and legislative compliance (licence to operate). These outages cannot be moved within defined periods or without a proper risk assessment being performed. More flexibility is applied to sustaining, strategic and betterment outages to manage the short-term capacity constraints. Currently all mandatory and a portion of sustaining and strategic outages are accommodated within the outage schedule to minimise risk to production **while balancing the impact of loadshedding on the country's economic and social wellbeing.**

The same allocation process has been applied to technical plan projects with the current prioritised projects. The latter is composed of all mandatory and those sustaining and strategic projects with a high certainty of execution. This results in a further refinement of the sustaining and strategic projects. Effectively all betterment technical plan projects have been deprioritised. The impact of not executing the sustaining and strategic projects will compromise the pace of the Generation Operational Recovery which has begun showing positive results or would have negative impact to plant safety, compliance, reliability or performance.

15.2.3 Future Fuel

15.2.3.1 Coal & Water Future fuel capital expenditure

Eskom invested capital expenditure of R1 527m (excluding IDC) against the assumption in the application of R2 349m in FY2025. NERSA did not allow for any future fuel. Historic underinvestment in the cost-plus mines continued to be corrected in FY2025. The nature of investing in coal mines with regards to cost-plus mines is a long-term investment. The repercussions of the delay in, and the lack of, investment in preceding years is evident in the decline in production from the cost-plus mines. Additionally, as mines age, and as new areas may need to be opened up, there is more uncertainty as to the impact of geology on production.

The following made up the bulk of the variance in FY2025 compared to the application:

- The Kriel opencast pits were not proceeded with because of problems experienced with land valuations and purchases. Subsequently, it became apparent that the coal from these pits would be too expensive to mine and the project was shelved.
- The Khutala life extension will not be done in the manner initially assumed. The latter is being conducted on a smaller scale to contain costs and to meet coal quality requirements. A smaller version of the project is underway. The variance is a result of projects being rephased.

15.2.3.2 Nuclear Future fuel

The actual nuclear future fuel capex was R1 485m. NERSA did not allow for any nuclear future fuel. Nuclear fuel procurement (i.e. Nuclear future fuel capex) comprises the acquisition of uranium, conversion, enrichment, and the fabrication of the fuel assemblies for nuclear fuel. Long-term contracts are established to ensure security of supply as well as availability of nuclear fuel at the appropriate time and within the prescribed quality standards. The nuclear fuel is held in inventory until such time as it is placed into the reactor and burnt.

The fuel manufacturing process is approximately eighteen months with contractual progress payments throughout the fuel manufacturing cycle. Fuel procurement volumes will fluctuate as they follow the delivery requirements for Koeberg. Fuel is required to be delivered approximately six months prior to each refuelling outage.

All the nuclear fuel expenditure is incurred in foreign currency and cash flow hedge accounting is applied to the purchases. The cashflow hedge accounting requires a basis adjustment to the price of the delivered fuel.

Nuclear fuel costs mainly comprise four categories, being uranium (48%), uranium conversion (6%), uranium enrichment (23%) and fuel assembly manufacturing (23%). The costs contribution per category depends on market prices and the ruling exchange rates and as per the latest available term-market prices. The cost of the delivered nuclear fuel is expensed as part of Koeberg's primary energy costs over the period that the assemblies remain in the reactor, which is normally between 45 and 54 months. Thus, there is not a direct correlation between when the nuclear fuel procurement costs are incurred and when it is expensed as primary energy costs.

15.3 NTCSA Capital Expenditure

15.3.1 Background

The key transmission capital requirement drivers include:

- Network strengthening and expansion investments to connect new generators and loads to the grid as well as to create new and expand existing power corridors.
- Asset replacement - to replace asset which have reached the end of their useful life in order to ensure reliability and continuity of supply
- EIA and servitude acquisition for strengthening and expansion projects
- Asset purchases such as acquisition of vehicles, IT equipment, workshop and furniture equipment.

Table below summarises the Transmission capital application, NERSA revenue determination and actual expenditure for FY2025.

TABLE 45: TRANSMISSION CAPITAL EXPENDITURE (RM)

NTCSA Capex (Rm)	Application FY2025	Decision FY2025	Actual FY2025	Variance
Strengthening and Expansion	10 988	10 988	3 668	(7 321)
Asset Replacement	2 040	-	2 240	2 240
EIA and servitudes	265	265	86	(179)
Telecom		-	236	236
Total Capex for Work Under Construction (WUC)	**13 293**	**11 253**	**6 230**	**(5 024)**
Asset Purchases	25	25	243	218
Total NTCSA Capex	**13 318**	**11 278**	**6 473**	**(4 806)**

The MYPD 5 capital expenditure application assumption for FY2025 was for a total value of R13 318m and NERSA revenue determination was a total of R11 278m (including asset purchases). The applied Asset replacement of R2 040m was not allowed. Total capital expenditure of R6 473m was incurred in FY2025 resulting in a variance of R4 806m against the NERSA decision. The details and motivations for each of the above-mentioned categories are outlined below.

15.3.2 Grid Asset Replacement and Telecom

The roll out of the refurbishment plan is primarily based on the replacement of poor condition assets (e.g. deterioration due to age, no longer meeting technical specification etc), poor performing assets (high failure rate requiring immediate replacement of asset) or obsolete equipment which is no longer supported by supplier with little or no spares availability.

Asset replacement capital expenditure includes costs for acquisition of transmission plant equipment used in repairs and replacement plant components. Additionally, insurance-related capital expenditure covers the replacement or restoration of assets damaged due to unforeseen incidents such as equipment failures, accidents, or natural events.

During the MYPD 5 revenue application, NERSA disallowed asset replacement on the basis that, in the revenue application, no assets were shown to have reached their useful life and can be taken out of the NTCSA RAB to allow them to stop earning depreciation and return. Furthermore, the regulator concluded that these assets should be placed on the NTCSA RAB only when they are 'used or usable', implying only when they are transferred to commercial operation. It should be noted that asset replacement is an ongoing process for network businesses. Thus, they are used and usable. Failure to replace and renew assets arising from lack of funding will result in declining technical performance, compromised grid reliability and will likely have a negative impact on maintenance and operational costs.

15.3.3 System Strengthening & Expansion Investments

The overall variance in system strengthening and expansion investments is a consequence of historic capex reductions in previous years, together with delays in obtaining environmental approvals and securing of land which impacts the number of projects handed over for execution.

The variance is primarily due to several projects still undergoing commercial processes and pending budget approvals, which have consequently been deferred to the next financial year. With respect to other projects, delays are related to poor contractor performance, community unrest, servitude access, supplier performance (e.g. steel availability), weather conditions, delayed placement of major contracts (auxiliary transformers) and transformer delivery constraints.

15.3.4 EIA and Servitudes

The variance is primarily due to outstanding Environmental Impact Assessments (EIA) reports from the environmental consultants, delay in acquisitions as well as protracted servitude negotiations. The timely completion of servitude acquisition process is dependent on different stakeholders outside NTCSA control such as landowners and tribal authorities (where Transmission lines traverse), deceased estates, municipalities, the Department of Forestry, Fisheries and Environment, and the Deeds Office.

The acquisition process for the following strengthening projects is behind schedule: GEL, Botswana, Blanco, Etna Glockner, Highveld Lowveld, Tshwane Metro, Upington, Namaqualand, Sigma-Theta, Paulputs, Mitchells Plain, Melmoth, Sorata Substation, Roodepoort Strengthening, Perseuz-Zeus, West Rand Strengthening,Melmoth Invubu, Hlaziya Grassridge, Namaqualand Strengthening Phase 2: Groeipunt Aggeneis, Kusile integration, Kookfontein strengthening, Mercury Ferrum Garona and Johannesburg East strengthening projects.

15.3.5 Completed & Commissioned Assets

TABLE 46: TRANSMISSION COMPLETED AND COMMISSIONED ASSETS

Asset Category	Strengthening and expansion	EIA and Servitude	Asset Replacement	Total WUC Capex (excl. Telecoms)
Capital Expenditure (excl. Asset Purchases) - Rm	**3 668**	**86**	**2 240**	**5 994**
Line Assets Capex (Rm)	2 397	84	129	2 610
Substation & Auxiliary Assets Capex (Rm)	1 271	2	2 111	3 384
Total Line Assets in km	**292.6**	**-**		**292.6**
- 765kV	-	-	-	-
- 400kV	292.6	-		292.6
- 275kV		-	-	-
- 132kV	-	-	-	-
Transformer installed capacity and commissioned (MVA)	**2 620**	**-**	**-**	**2 620**

As at March 2025, the total transmission lines installed was 292.6 km. This achievement was driven by progress on four major transmission projects:

- Waterberg GX Integration (Medupi - Witkop 400kV Line) contributing 163.8 km,
- Neptune - Pembroke 400kV Line adding 34.9 km,
- Ariadne - Eros 400kV Line delivering 59.1 km and
- Aries - Upington 400kV Line delivering 33.6 km

The total transformer capacity commissioned has reached 2 620 MVA, comprising 2 040 MVA of transformation capacity delivered through capital projects and a further 580 MVA delivered via self-build projects.

15.3.6 Asset Purchases

Asset purchases include all movable items that are purchased and ready to be used, e.g. equipment, vehicles and production equipment. NTCSA asset purchases amounts to R243m compared to the FY2025 MYPD 5 decision of R25m. The variance is primarily due to purchase of aircraft as well as workshop and laboratory equipment.

NTCSA is embarking on an aviation equipment replacement programme, which entails the replacement of seven rotor-wing aircraft (helicopters). These aircrafts are required for maintenance of overhead lines. The capital expenditure of R135 million represents a 20% deposit towards the acquisition of these aircraft. In addition, the workshop and laboratory equipment comprises gas detection meters and testing instruments that support the identification of sulphur hexafluoride (SF6) gas leaks within the Grid. This equipment, including a SF6 leak detection camera, enables visual confirmation of leak locations and assists in accurately determining the scope of repair work, thereby contributing to the reduction of SF6 emissions.

TABLE 47: TRANSMISSION ASSET PURCHASES (RM)

Asset Purchases	Actual FY2025
Workshop Equipment	57
Laboratory Equipment	30
Computer Equipment	11
Office Equipment	3
Aircraft	135
Buildings and Facilities	5
Other Production Equipment	1
Total	**243**

15.4 Distribution Capital Expenditure

The FY2025 capital expenditure is reflected in the table below.

TABLE 48: DISTRIBUTION CAPEX (RM)

Dx Capex (Rm)	Application FY2025	Decision FY2025	Actual FY2025	Variance
Direct Customers	1 384	1 384	1 108	-276
Strengthening	2 193	2 193	886	-1 307
Refurbishment	1 868	0	1 109	1 109
Land & Rights	59	59	5	-54
IPP Connections	1 030	1 030	28	-1 002
BESS	2 074	2 074	0	-2 074
Other	-	-	372	372
Total Capex for WUC	**8 608**	**6 740**	**3 508**	**-3 232**
Asset Purchases	492	492	604	112
Eskom funded	**9 100**	**7 232**	**4 112**	**-3 120**

More specifically by Capex category:

- **Direct customers connections**: These customers are supplied directly by Eskom Distribution and their minor works connection projects exclude electrification customers funded by the Department of Electricity and Energy (DEE) electrification programme. Investment requirements for Direct customers vary based on the number of new connection applications. During FY2025, project delivery was hindered by shortages of critical materials. This was compounded by the country's economic downturn contributing to fewer customer applications.
- **Network strengthening**: This is the expansion and upgrading of plant to increase capacity or improve the quality of supply and supports the aversion of network constraints enabling future load growth.
- **Refurbishment**: The need for refurbishment was higher in the Eskom Distribution network leading to R1 109m expenditure during FY2025 despite the lack of a NERSA provision for

this network sustainability activity. Refurbishments are essential for extending the life of network assets and achieving expected performance levels for reliable supply which in the long run contributes to the financial efficiency in network management.

- **Land and rights**: Delays in customer negotiations, permissions and challenges in acquiring land and rights hindered the expenditure in this area.
- **BESS** capital expenditure is addressed as part of the Generation submission.

16 Integrated Demand management (IDM)

Integrated Demand Management (IDM) promotes more efficient electricity use across the system. Its purpose is to reduce long-term energy costs and support the sustainability and reliability of the electricity network.

The FY2025 MYPD decision did not allocate costs for IDM. Limited costs were expended within existing programmes relaunched in April 2023 to maintain essential demand-side management efforts. Eskom implemented these targeted initiatives to address operational requirements and strategic priorities that support system stability and improve overall load-profile management.

These activities were focused on execution of reducing local network constraints, improving load factor, and deferring certain capital investments by managing demand more effectively in targeted areas. The actual spending reflects Eskom's efforts to reintegrate IDM into its operational strategy despite the absence of a specific regulatory allowance for the period.

The IDM operating costs were R68m for FY2025 is driven by other costs consisting of Marketing, M&V and provisions for older IDM projects. See Table below.

TABLE 49:IDM OPERATING COSTS (RM)

IDM: Other expenses (Rm)	Application FY2025	Actuals FY2025	Decision	RCA adjustments	RCA FY2025
Employee benefits	82	25	0	(1)	25
Maintenance	-	-	-	-	-
Other Opex	341	43	0	-	43
Arrear Debt	-	-	-	-	-
Other income	(1)	-	-	-	-
Depreciation	-	-	-	-	-
Total operating costs	**422**	**68**	**(0)**	**(1)**	**(68)**

17 Operating costs

Operating costs comprises employee benefits, maintenance, other operating costs and other income. It excludes corporate overheads which are treated separately for RCA purposes.

MYPD Methodology - Operating costs – treatment for RCA

17.1.1.4 Adjusting for prudently incurred over or under-expenditure on operating costs as may be determined by the Energy Regulator.

As required by the NERSA methodology, it is incumbent upon NERSA to determine the prudency of the variances submitted by Eskom. Detailed analysis of the actuals needs to be undertaken to determine the prudent variance. Eskom has provided detailed motivations for the variances from the NERSA decision, as required by the methodology.

A summary of the key principles on operating costs, as reflected in the MYPD methodology (Section 10.4) are:

- Expenses must be incurred in the normal operations and supply of electricity, including an acceptable level of repairs and maintenance costs.
- Allowance for the human resources costs should be at reasonable levels.
- Expenses forecast will be based on the most recent prudently and efficiently incurred actual costs taking into account the fixed and variable nature of such costs.

17.1 Variances in Total Eskom Operating Costs

TABLE 50: SUMMARY OF ESKOM OPERATING COSTS (RM)

Allowed operating costs (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Employee benefits (incl. GTD, Cx, SAE, EEDSM)	28 879	37 950	9 070	(4 256)	4 814
Maintenance	20 758	29 847	9 089	-	9 089
Other Opex	8 522	19 550	11 028	(539)	10 489
Arrear Debt	-	20 381	20 381	(20 449)	(68)
Corporate Services (excl. EB)	4 168	4 136	(32)	(1 569)	(1 601)
Other income	(1 232)	(1 953)	(721)	-	(721)
Less: Corporate Social Investment	(124)	-	124	-	124
Total Allowed Opex	**60 971**	**109 911**	**48 940**	**(26 813)**	**22 127**

Adjustments include:

- **Employee Benefits** – This relates to short-term incentives and production bonuses paid to qualifying employees based on performance. These costs are being borne by Eskom in this submission and are excluded from the RCA application.

- **Other Opex** – This includes adjustments for corporate social investments, Majuba rail write-off, expected credit loss adjustments on financial assets and stock losses.
- **Arrear Debt** – This amount is excluded as NERSA did not allow for any arrear debt in the MYPD5 decision and alluded to the fact that this would be managed by Government outside of the MYPD process. The R68m movement in the impairment for International Trader as at 31 March 2025 reflects a decrease in the impairment provision from R597m on 1 April 2024 to R530m at year-end. This reduction is primarily due to lower outstanding debt balances from international trading partners by 31 March 2025, resulting in a lower impairment provision compared to the prior year.
- **Corporate Services** – This includes adjustments to corporate social investments.

The overall operating costs variance, after adjustments, is R22bn. All elements of operating costs, with the exception of Corporate Services and other income illustrates variances in favour of Eskom. The variances are explained below in each section.

17.1.1 Generation Total Operating costs

Operating expenditure is actively managed to ensure that it is at prudent and efficient levels. As part of this management process, costs are benchmarked against international norms.

Eskom strives to operate within international benchmarked norms unless there is strategic intent to increase maintenance to improve technical performance due to ageing plant or higher utilisation compared to international benchmarks.

TABLE 51: GENERATION OPERATING COSTS (RM)

Generation Operating Costs (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Employee expense	Eskom Level	16 627	Eskom Level	(2 160)	Eskom Level
Maintenance	13 910	23 205	9 296	-	9 295
Other Opex	Eskom Level	14 057	Eskom Level	(2 387)	Eskom Level
Arrear debt	-	-	-	-	-
Other Income	(470)	(688)	(218)	-	(218)
Less: Corporate Social Investments	-	-	-	-	-
Gx Operating costs for RCA purposes	Eskom Level	**53 201**	Eskom Level	**(4 546)**	Eskom Level
Add: SAE opex for RCA purposes	41	(41)	(82)	-	(82)
Total Operating costs for RCA purposes	Eskom Level	**53 161**	Eskom Level	**(4 546)**	Eskom Level

Note: Total excludes Corporate overheads

TABLE 52: SAE OPERATING COSTS

SAE: Operating costs (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA Adjustments	RCA FY2025
Employee benefits	41	24	(17)	-	(17)
Maintenance	-	-	-	-	-
Other Opex	0	3	3	-	3
Arrear Debt	-	(68)	(68)	-	(68)
Other income	-	(0)	(0)	-	(0)
Depreciation	-	-	-	-	-
Total operating costs	**41**	**(41)**	**(82)**	**0**	**(82)**

The NERSA determination for employee benefit expense, and other operating cost were made at an Eskom level.

17.1.1.1 Benchmarking Generation Total Operating Costs

It is acknowledged that comparison to operational cost benchmarks is not always simple nor an exact science due to the complexity in the status of various power plants. Sources of benchmark data may vary significantly from Eskom plant in terms of equipment, age, maintenance philosophy and overall condition of plant. To improve confidence in Generation's costs or stimulate investigation if costs do not compare favourably, certain comparisons have been undertaken for Eskom's coal power plants. They give an indication of level of cost comparatively to other similar utilities.

Total opex comprises of manpower, maintenance, other opex and outage capex. Because of the subjectivity of capitalising or expensing maintenance costs, in order to potentially avoid understating Generations' maintenance costs, for purposes of this benchmarking exercise, outage capex has been included under the ambit of total opex.

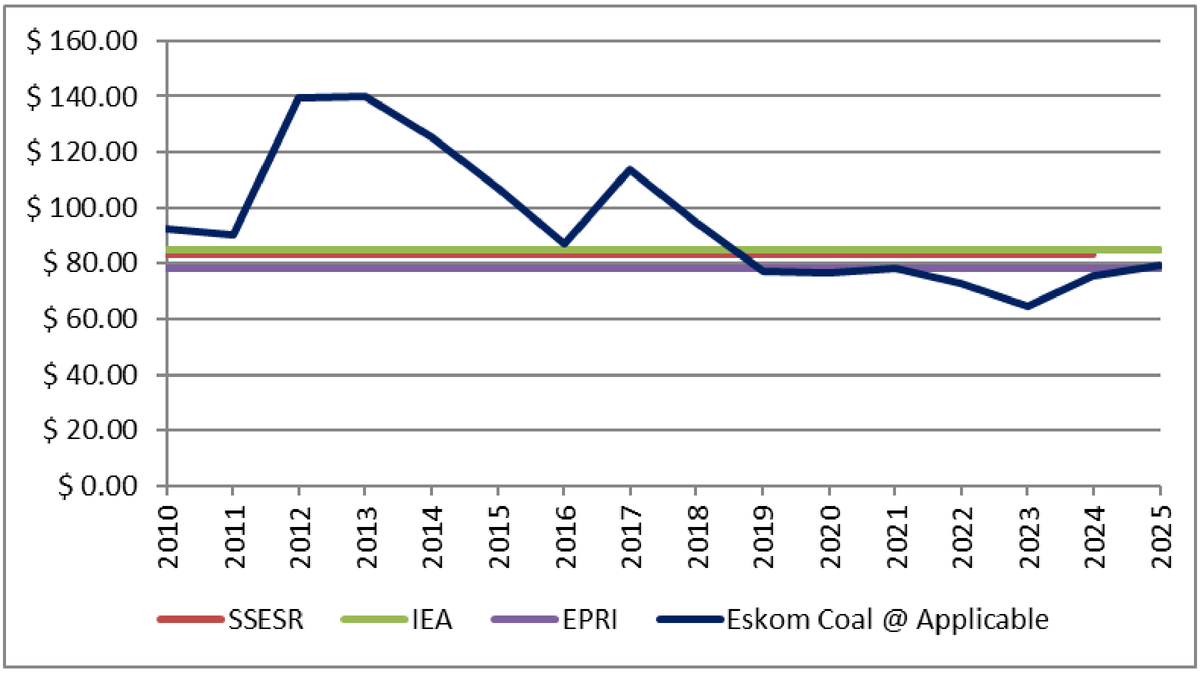
TABLE 53: GENERATION TOTAL O&M BENCHMARK FY2025

Source	Total O&M ($/kW/Year)
SSESR	$83.40
IEA	$84.92
EPRI	$78.42
Eskom	**$79.26**

All of these independent benchmarks are within a 10% range of each other, hence can be considered to be a reasonable representation and basis of comparing Generation's costs.

Note that Generation's operating and maintenance (O&M) for purposes of this comparison includes Outage Capex

FIGURE 5: BENCHMARK COMPARED TO REAL O&M $/KW (COAL STATIONS ONLY)



Note: Eskom coal plants @ applicable exchange rate in that year.

It should be noted that these benchmarks reflect costs that are 'levelised' over the station life cycle (i.e. which smooths the benchmark), whereas the comparison is to Generation's coal power stations' annual costs, the bulk of which are in mid-life cycle which implies higher costs for mid-life refurbishment and maintenance backlogs, etc.

In addition, the high utilisation of the Eskom power stations over a number of years, combined with deferral of some maintenance due to insufficient national system capacity, has placed unusually high stress on plant systems and components and accelerated technical deterioration which would also increase operating and maintenance costs.

Bearing this in mind one would expect the Eskom costs to be higher than the benchmark. However, at the applicable exchange rate, Generation's Opex is in line with all the international benchmarks which serves to highlight the reasonability of Generation's Opex. It should also be borne in mind that *continued under-expenditure is unsustainable and poses a risk to operational sustainability.*

Eskom strives to operate within these international benchmarked norms, unless there is strategic intent to increase maintenance to improve technical performance due to ageing plant or higher utilisation compared to international benchmarks.

17.1.2 Variances in NTCSA Operating Costs

NTCSA Operating costs encompass all expenses incurred in the transmission of electricity. These costs include employee benefits, maintenance, other operating costs, and other income.

TABLE 54: VARIANCES IN TRANSMISSION OPERATING COSTS (RM)

NTCSA operating costs (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Employee expense	Eskom Level	4 514	Eskom level	(518)	Eskom level
Maintenance	1 117	1 364	247	-	247
Other Opex	Eskom Level	(43)	Eskom Level	1 855	Eskom Level
Other Income	(120)	(617)	(496)	-	(496)
Total Operating costs for RCA purposes	Eskom Level	**5 218**	Eskom Level	**1 337**	Eskom Level

Note: Total excludes Corporate overheads

The FY2025 NTCSA operating costs is made up of employee benefit costs amounting to R4.5 bn, which is driven by increased staff numbers, higher-than-assumed annual salary adjustments, and short-term incentive payments, although these bonuses were excluded from the RCA application. Maintenance costs were 22% higher due to increased work on lines, plants, and transformers. Other operating costs includes abnormal transactions arising from amortisation the financial guarantee liability, impairment of financial assets, and scrapping assets. Operating costs are partially offset by other income received from insurance proceeds as well as from telecommunications and fibre network services.

17.1.3 Variances in Distribution Operating Costs

TABLE 55: DISTRIBUTION OF OPERATING COST (EXCLUDING IDM) – RM

Distribution Operating Costs (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustment	RCA FY2025
Employee benefit cost	Eskom level	14 330	Eskom level	(1 159)	Eskom level
Maintenance	5 731	5 277	(454)	-	(454)
Other expenses	Eskom level	5 490	Eskom level	(7)	Eskom level
Arrear debt	0	20 449	18 782	(20 449)	-
Other income	(532)	(648)	(115)	0	(115)
Less: Corporate Social Investments	0	0	-	0	-
Total Operating costs for RCA purposes	Eskom level	**44 899**	Eskom level	**(21 615)**	Eskom level

Note: Total excludes Corporate overheads

Variances in employee benefit costs, maintenance activities, and other operational expenses are detailed in the relevant sections of this application.

17.2 Employee Benefit costs

The NERSA MYPD5 Reasons for Decision did not apportion its decision per licensed activity. In the absence of such apportionment, the base of the RCA motivation is a comparison between the actual expenditure and costs that were included in the revenue application.

At the time of the MYPD5 Revenue Application the re-linking of line divisions was not taken into account as noted in the FY2023 RCA Application (Par. 18.7 page 144 of 159):

"In preparation for the divisionalisation or ring-fencing of Eskom, some of the operational level services which formed part of the approved spend, have been relinked to the line divisions, Generation, Transmission and Distribution. Group Technology has been relinked from a central corporate role to Generation. Hence all costs associated with these services now reside within the line division.

Services including finance, security, procurement, fleet services and revenue management within the remaining corporate functions, which are considered to be better managed within the licensees, have also been relinked."

It is important to note that this will have a knock-on effect throughout the MYPD 5 period (FY2023 – FY2025).

In the FY2023 RCA RfD NERSA corrected the base by taking Eskom's business model into account reflecting the true cost of the licensees including SAE, IDM and corporate services. NERSA considered all elements when it assessed the application for employee benefit costs before the final determination was made. This corrected base must be used as the starting point for future revenue and RCA applications.

The table below provides a summary of the Eskom employee benefit costs applied for in the RCA for FY2025.

TABLE 56: SUMMARY OF ESKOM EMPLOYEE BENEFIT COSTS (RM)

Employee Benefits costs (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Generation		16 627		(2 160)	
Transmission	Eskom level	4 514	Eskom level	(518)	Eskom level
Distribution		14 330		(1 159)	
Total GTD	**25 344**	**35 471**	**10 126**	**(3 836)**	**6 290**
SAE	41	24	(17)	-	(17)
EEDSM	82	25	(57)	(1)	(57)
Corporate services	3 412	2 430	(982)	(419)	(1 401)
Grand Total	**28 879**	**37 950**	**9 070**	**(4 256)**	**4 814**

17.2.1 Generation Employee Benefit costs

Employee benefit costs are driven by the following:

- The ***number of employees*** – Permanent employees and full-time equivalents (FTE's)
- The ***cost per employee*** - Salary adjustments and cost of living adjustments, other adjustments such as medical aid premiums.

17.2.1.1 Employee Numbers in FY2025

The increase in employee numbers and associated employee costs within the Generation Licensee for FY2025 is a direct outcome of Eskom's strategic workforce plan, which was implemented to address operational stability, skills shortages, and future sustainability in the generation business. During the year, the Generation's employee numbers increased as a result of targeted recruitment to fill core and critical technical roles essential for maintaining and improving plant performance, reliability, and compliance with operational targets. This hiring drive was necessary to support the successful execution of the Generation Recovery Plan, which underpinned Eskom's turnaround in energy availability and reduction in loadshedding. The workforce plan also prioritised succession planning and the development of a robust learner pipeline, ensuring that the division is equipped to replace retiring or departing staff and to build future-ready capabilities. In addition, the plan supported transformation and inclusion objectives, contributing to the appointment of more women, people with disabilities, and youth, in line with Eskom's employment equity and skills development commitments. These actions were essential to secure the technical capacity required for safe, reliable, and efficient power generation, and to support Eskom's broader strategic objectives. As a result, the increase in employee numbers and costs in the Generation Licensee for FY2025 is both planned and justified, reflecting a deliberate investment in operational excellence, compliance, and long-term sustainability.

The employee numbers for Generation in the FY2025 period are as follows:

TABLE 57: GENERATION EMPLOYEE NUMBERS

Gx Employee Numbers	Application FY2025	Decision FY2025	Actuals FY2025	Variance
Employee numbers	12 427	Eskom Level	14 253	Eskom Level

The employee numbers related to SAE for the FY2025 period are:

TABLE 58: SAE EMPLOYEE NUMBERS

SAE Employee Numbers	Application FY2025	Decision FY2025	Actual FY2025	Variance
SAE Employee Numbers	33	Eskom Level	17	Eskom Level

17.2.2 Generation Employee Benefit Costs in FY2025

The employee numbers result in the following Employee Benefits costs for Generation.

TABLE 59: GENERATION EMPLOYEE BENEFIT COSTS (RM)

Gx Employee Benefits (Rm)	Application FY2025	Decision FY2025	Actuals FY2025	Variance
Employee Benefit Costs	11 813	Eskom Level	16 627	Eskom Level

The SAE employee numbers result in the following Employee Benefits costs.

TABLE 60: SAE EMPLOYEE BENEFIT COSTS (RM)

SAE Employee Benefit Costs (Rm)	Application FY2025	Decision FY2025	Actual FY2025	Variance
SAE Employee Benefit Costs	41	Eskom Level	24	Eskom Level

The Generation employee benefit cost detail is reflected in the table below.

TABLE 61: GENERATION EMPLOYEE BENEFIT COSTS (RM)

Gx Employee Benefit Costs (Rm)	Application FY2025	Actual FY2025
Salaries	9 431	11 337
Overtime	913	1 713
Post Retirement Medical Aid	136	158
Leave Pay	352	422
Performance bonus		2 159
Pension benefits	846	1 222
Direct Costs of Employment	**11 678**	**17 011**
Temporary staff	125	190
Training and Development	56	47
Other Staff Costs	197	404
Indirect Costs	**379**	**641**
Capitalised to Property, Plant & Equipment	(245)	(1 025)
Total EB Costs	**11 813**	**16 627**
*RCA Adjustment	-	(2 160)
Net Employee Benefit Costs for RCA Purposes	**11 813**	**14 467**

*** Note:** The adjustment pertains to Incentive Bonus payments, these costs are not included in the RCA claim.

- **Salaries**

The increase in the number of employees relate to the recruitment of core and critical skills in Generation. There was also an increase in FTEs because of learner intake undertaken through Eskom's Youth Employment Services (YES) programme which were not included in the application assumptions (204 in Generation and 612 across the business). Approximately 78.1% of the Generation licensee staff complement belongs to the bargaining unit and 21.1% are positioned at managerial and 0.8% executive level.

In FY2025, an annual salary adjustment of 7% was implemented for bargaining unit employees from 1 July 2023. While an average 7% increase for managerial remuneration costs was implemented from 1 October 2023.

- **Overtime**

Overtime costs relate to shifts performed by staff in various plant areas and departments at power stations beyond their normal working hours, to ensure that the plant is managed and maintained accordingly. This includes working on Saturdays, Sundays, and public holidays. It is important to note that overtime is in place to enable the business to recover operations.

- **Post Retirement Medical Benefits**

The post-retirement medical benefits is a provision for post-retirement medical aid contributions for certain in-service members and pensioners. This benefit forms part of certain permanent employees' annual package and is driven by the number of employees.

- **Leave**

Leave pay relates to a monthly provision for leave based on leave accumulated by employees. Provisions for leave pay are split between annual leave and service or occasional leave.

- **Pension Benefits**

Pension Benefits is the Eskom contribution to the pension fund as included in the conditions of service.

- **Training and Development**

This is attributable to employees attending external training at a university or other training institution (including training material). Examples include developing technical skills of the employees.

- **Temporary and contract staff costs**

Costs for temporary and contract staff include:

- Salary and wages of non-permanent staff, including vacation students.
- Non payroll temporary staff: Labour cost of persons employed as temporary staff not paid via payroll with other permanent employees.

- **Other staff costs**

Other staff costs include professional institution fees paid to professional bodies on behalf of employees e.g. ECSA, SAICA, CIMA. Recruiting expenses, skills development levies, bursaries and scholarships.

- **Employee Benefit Recovery Postings (Assessments)**

The employee benefit recovery postings are influenced by the change in cost allocation method. Labour expenses of the business units that provide dedicated services to the line divisions are directly allocated to those divisions and form parts of their employee benefit costs and not included in corporate overheads as per previous practice.

- **Capitalised to property plant & equipment**

The capitalisation of the manpower costs related to capital projects.

17.2.3 NTCSA Employee Benefit Cost

TABLE 62: NTCSA EMPLOYEE NUMBERS

Tx Employee Numbers	Application FY2025	Decision FY2024	Actual FY2025	Variance
Employee Numbers	3 226	Eskom Level	3 815	Eskom Level

TABLE 63: NTCSA EMPLOYEE BENEFIT COSTS (RM)

Tx Employee Benefits (Rm)	Application FY2025	Decision FY2025	Actual FY2025	Variance
Employee Benefit Costs	3 063	Eskom level	4 514	Eskom Level

NTCSA's MYPD5 revenue application acknowledged the need for fundamental operational changes to provide sustainable electricity supply to all South Africans. As far as human capital is concerned, this can be achieved through NTCSA's remuneration and benefits framework which is designed to attract, retain and motivate a skilled and high-performing workforce, while remaining aligned with market benchmarks and shareholder expectations. This approach balances financial sustainability with the need to reward excellence and support employee wellbeing subject to the conditions of the Eskom Debt Relief Act, 2023.

17.2.3.1 Transmission Employee Benefit Cost drivers

As at 31 March 2025, NTCSA's total employee numbers, including permanent employees and fixed-term contractors, was 3 815, reflecting a 12% increase compared to the previous financial year. This growth was driven by the need to strengthen critical operational areas and support NTCSA's transition into a fully independent entity. Key resourcing priorities included:

- **Transmission Development Plan (TDP) Delivery and Plant Maintenance**: Over 70% of the 429 additional resources were deployed to functions responsible for accelerating grid expansion, asset replacement projects as well as maintenance of the existing network. This includes Grids, Engineering, Asset Management, and Projects business areas.
- **System Operator Capacity:** A fully resourced System Operator business unit is critical to ensure transmission system reliability and security, particularly in the light of the increased penetration of renewable generation sources into the grid.
- **Corporate Support Functions**: Enhanced capacity within the Office of the Chief Executive (covering Legal Services, Information Management, Communication) as well as Human Resources, Finance, and Procurement, was essential to enable efficient operations and governance as NTCSA assumes greater responsibilities as a separate legal entity

Employee costs are driven by both volumes and price. Approximately 65% of NTCSA licensee staff complement belongs to the bargaining unit and 35% are positioned at managerial and executive level. The wage settlement agreement has a significant impact on the employee benefit costs because of the high proportion of bargaining unit employees. It must be noted that as part of the legal separation agreement, NTCSA employees are still subject to Eskom conditions of service until 30 June 2026.

Employee benefit costs are influenced by the following factors:

- Employee numbers – NTCSA has increased its workforce by 412 compared to FY2024 to better capacitate the new entity delivering on its primary mandate to deliver on the TDP objectives.
- NTCSA implemented 7% salary adjustments in FY2025 for bargaining and an average of 7% salary adjustment for managerial level employees. In addition to salary adjustment, there are other annual cost of living (CPI) adjustments on housing allowance of all bargaining unit employees. Other adjustments include medical aid.
- NTCSA workforce comprises a significant number of highly skilled professionals, necessitating a retention cost premium. NTCSA operations demand specialised expertise in fields such as System Operations (SO), Grid Planning and Engineering.

TABLE 64: TRANSMISSION EMPLOYEE BENEFIT COSTS (RM)

NTCSA Employee Benefit Costs (Rm)	Application FY2025	Actual FY2025
Salaries	2 761	3 406
Overtime	76	107
Post Retirement Medical Aid	37	39
Leave Pay	100	149
Performance bonus	-	518
Pension benefits	254	384
Direct Costs of Employment	**3 228**	**4 603**
Temporary staff	29	21
Training and Development	31	41
Other Staff Costs	56	156
Indirect Costs	**115**	**219**
Capitalised to Property, Plant & Equipment	(280)	(308)
Total EB Costs	**3 063**	**4 514**
*RCA Adjustment	-	(518)
Net Employee Benefit Costs for RCA Purposes	**3 063**	**3 996**

* **Note:** The adjustment pertains to Incentive bonusses, these costs are not included in the RCA claim.

Direct cost of employment is higher than in the application. This is primarily due to salaries and salaries related costs other adjustments such as medical aid premiums when compared to the application as explained below.

- **Salary related costs (Salaries, Pension benefits and overtime)**

The price variance is primarily attributable to salary adjustments implemented during the financial year. Bargaining unit employees received a 7% across-the-board increase in July 2024 in line with the bargaining agreement concluded between Eskom and its recognised trade unions. Managerial-level employees received an average salary increase of 7% in October 2024, which included a discretionary component awarded to top performers as a retention incentive.

The volume variance is mainly driven by staff numbers which increased by 19%, which is higher than that assumed in the FY2025 MYPD5 application. This increase is necessary to ensure adequate resourcing to accelerate grid expansion and maintenance, strengthen system operations, and build corporate capacity as NTCSA transitions into a standalone entity.

- **Leave pay provision**

The main driver of leave pay is the leave encashment that employees exercise in lieu of occasional/service leave that they have accumulated. It is linked to salary adjustment.

- **Employer Contributions**

The variance in employer contributions is structuring of salaries and medical aid options/packages that employees take.

- **Performance Bonus**

The Board approved the reimplementation of the short-term incentive scheme for FY2025 to drive operational performance excellence and support employee retention. The scheme was approved by the overall shareholder, as required under the debt relief conditions. It has contributed to improved employee morale and commitment, supported the retention of scarce and critical skills, and reinforced efforts to build a high-performance, ethical culture, as evidenced by significant improvements in technical performance. These costs were not included in the RCA application.

- **Training and Contract Staff**

NTCSA has embarked on robust learner recruitment as a strategy to address relative scarce skills gap and build critical capabilities. By 31 March 2025, NTCSA had 394 non-permanent employees comprising of Learners (including Graduates in Training (GIT), Engineers in Training (EIT), Artisans) and other third-party Contractors.

- **Capitalisation of Employee Benefit Costs**

The increase in capex expenditure resulted in more work executed in the capital programme environment therefore the higher capitalisation of employee benefit cost.

17.2.4 Distribution Employee Benefit Cost

In FY2025, Distribution increased its investment in employee development and recognition while optimising overall employee numbers. As a result, employee benefit costs rose primarily due to higher incentive payments. By the end of FY2025, the employee numbers was lower than projected in the MYPD FY2025 application. See Table below.

TABLE 65: DISTRIBUTION EMPLOYEE COSTS AND NUMBERS

Employee Benefits	Application FY2025	Actual FY2025
Employee benefit cost (Rm)	13 076	14 330
Headcount	17 234	15 712

The employee numbers and employee benefit costs for IDM is set out below.

TABLE 66: IDM EMPLOYEE NUMBERS

IDM Employee Numbers	Application FY2025	Decision FY2025	Actual FY2025
Employee numbers	80	-	18

TABLE 67: IDM EMPLOYEE BENEFITS COST (RM)

IDM Employee Benefit Cost (Rm)	Application FY2025	Decision FY2025	Actual FY2025
Employee benefit	82	-	25

The driver for the employee benefit costs was a focus on retaining essential skills needed to sustain reliable operations. A competitive and flexible reward framework was introduced to improve productivity and support readiness for future market and industry changes. Building a capable, multi-skilled workforce is necessary for Distribution to meet both current and emerging challenges.

Skilled employees are central to maintaining a stable, flexible, and customer-focused network. They deliver high-quality customer service while operating, maintaining, and safeguarding the electrical infrastructure. These capabilities ensure ongoing compliance with Distribution Licence conditions and support the reliability of the network. The key observations are:

- The overall EB costs were mainly higher due to the reinstatement of conditions of services increasing costs above related planned for salary increases, increased overtime to provide a better service and adjustments to housing allowances. To recognise improved performance, the Short-term incentive (STI) was introduced. The costs related to any bonus was not included in the RCA application.
- The favourable variance in indirect cost of employment was due to lower training cost and contractors/temporary staff.
- Capitalisation of employee benefit cost was because of the lower capital expenditure.

TABLE 68: DISTRIBUTION EMPLOYEE BENEFIT COST (RM)

Dx Employee Benefit Costs (Rm)	Application FY2025	Actual FY2025
Salaries	11 232	10 797
Overtime	518	832
Post Retirement Medical Aid	154	196
Leave Pay	379	406
Performance bonus	-	1 159
Pension benefits	1 022	1 175
Direct Costs of Employment	**13 305**	**14 565**
Temporary staff	382	30
Training and Development	129	44
Other Staff Costs	387	525
Indirect Costs	**898**	**599**
Capitalised to Property, Plant & Equipment	(1 128)	(834)
Total EB Costs	**13 076**	**14 330**
*RCA Adjustment	-	(1 159)
Net Employee Benefit Costs for RCA Purposes	**13 076**	**13 171**

*** Note:** The adjustment pertains to Production Bonus payments, these costs are not included in the RCA claim.

17.2.4.1 Distribution Employee Benefit Cost drivers

The key cost drivers for the underlying employee benefit costs are:

- **Maintain network functionality:**

Distribution continues to maintain network performance through the limitation of outage duration and the frequency of Network interruptions experienced by customers. A technically competent and skilled workforce is needed to manage the Network Infrastructure from a planned and corrective maintenance to perspective in compliance with electrical standards, safety and regulatory requirements. Employees should be trained in specialised competencies, have authorisation to work on the network in accordance with the applicable legislation and regulations.

- **Electrification expansion:**

The electrification programme has contributed immensely to the increase in Eskom customers. The increase emanates from the government electrification programme to grant customers in deep rural areas universal access to electricity. The increase in customer electrification connections requires the current employee base to respond to a rise in customer service level expectations.

- **Employee safety in operational work environment:**

Safety is still a cornerstone of Eskom's commitment to zero harm. It is imperative that employees are adequately equipped to operate in a potentially dangerous environment whilst complying to all legislative requirements.

- **Training & Development of Network Operators:**

The Licensee is obliged to train and develop operating staff in normal business operations, new technological advancements and new business Initiatives. Employees need to be upskilled and multi-skilled to operate the network and provide exceptional customer service. Employees must undergo mandatory legislative training requirements to be authorised to operate on the network.

- **Customer operations:**

Customer service is a very important link between the Distribution Business and the customer. In the light of the eminent changes and competition in the Electricity Distribution Industry it is of vital importance that Distribution retain and expand its customer base. The growth in customer numbers will require adequate resourcing of staff to fill the required Skilled work force complement of new Initiatives introduced by the Distribution Business.

- **Remuneration of employees:**

Employee costs are a function of the final negotiated wage settlement with trade unions. The current wage agreement comes to an end in this financial year; a new wage settlement will be negotiated which will have a significant impact on the Salary Bill.

17.3 Maintenance Costs

TABLE 69: SUMMARY OF MAINTENANCE COSTS (RM)

Maintenance costs (Rm)	Decision FY2025	Actuals FY2025	Variance
Generation	13 910	23 205	9 295
Transmission	1 117	1 364	247
Distribution	5 731	5 277	(454)
Total	**20 758**	**29 847**	**9 089**

A significant variance is seen in Eskom maintenance costs. This investment in maintenance has contributed to improved performance across generation, transmission and distribution. The continued implementation of the Generation Performance Turnaround Strategy has borne improved results in the generation performance in FY2025. This is evident by a marked decrease in the number of load shedding days as well in the severity of load shedding. The further focus on generation maintenance, as was not envisaged when the decision was made, contributed to the increased maintenance costs. The transmission plant is ageing, which adversely affects system reliability and necessitates sustained and intensified intervention.

17.3.1 Generation Maintenance Costs

In FY2025, Eskom continued to implement a comprehensive Generation Performance Turnaround Strategy to address persistent generation capacity shortfalls and restore fleet reliability. Central to this approach was the continuation of the “no further shutdowns” strategy (Continued operations), Eskom confirmed that no additional coal-fired units will be decommissioned before FY2030. This includes Arnot, Hendrina, and Kriel, which were previously scheduled for retirement. These plants will continue operating under the Continued Operations framework.

The change in strategy, as outlined above, represents a significant departure from the assumptions made during the MYPD 5 Revenue Application (Shutdown Strategy – Ramping down of units). Consequently, cost assessments should be realigned to reflect the requirements of the Continued Operations and Generation Recovery Plan as detailed in this application.

17.3.1.1 Classification of Generation’s Maintenance costs

Maintenance costs can be classified as either maintenance operating expenses (opex) or maintenance capital expenditures (capex). The Maintenance opex are recurring costs associated with routine and preventive maintenance activities aimed at keeping existing assets operational. Eskom classifies it in 4 different categories namely, ***Outage, Tech plan, Routine and Breakdown*** maintenance.

- **Outage Maintenance (Opex):** Planned maintenance performed on designated systems or components that require unit shutdown. The scope includes servicing and repairs that cannot be done while the plant is operational. Activities are subject to multidisciplinary review for cost justification, with efforts to extend outage intervals where feasible. Execution is guided by prudence and plant condition assessments.
- **Technical Plan Maintenance (Opex):** Comprises non-capital projects (including R&E) drawn from the first five years of the prioritised Life of Plant Plan (LOPP). These initiatives meet defined funding and execution criteria but do not qualify as capital investments.
- **Routine Maintenance (Opex):** Includes ongoing maintenance conducted during regular plant operation. This encompasses oil changes, minor servicing, mill maintenance, and other adjustments, including short, planned outages of less than 14 days.
- **Breakdown Maintenance (Opex):** Emergency corrective actions required to restore operations following unplanned equipment failures. These are critical for supply continuity and are monitored and minimised through trend analysis and proactive inspections.

It is important to note that this does not represent the total maintenance cost i.e., it excludes the capitalised portion which is categorised as Outage Capex and Tech Plan Capex. All these maintenance projects/initiatives are aligned to the Life of Plant Plan (LOPP). Maintenance (Capex) are investments in maintenance that significantly improve, upgrade, or extend the useful life of assets. This involves substantial repairs, refurbishments, or even upgrades to assets like turbines. Such work often enhances the asset's efficiency or capacity and has long-term benefits.

17.3.1.2 Maintenance Planning Process – The basis of maintenance spent

Generation applies asset management principles which include planning on how to ensure the optimal operating and maintenance of the existing fleet for the duration of its economic life, including inputs such as primary energy and major refurbishments. Planning for the operating and maintenance of the fleet can be separated into Maintenance Planning and Production Planning.

Maintenance Planning is informed by what maintenance needs to be performed, in terms of replacement/refurbishment of components of the assets as well as the routine outage maintenance activities. The Life of Plant Plan (LOPP) details these major maintenance and refurbishment projects that are required over the life of the plant. The Technical Plan is a more refined extract of the LOPP over a shorter period and the Maintenance Plan is a listing of the outages required to implement the LOPP and Technical Plans. The Capacity Plan then takes a detailed view of the first year of the Maintenance Plan to ensure that all required outages are scheduled whilst ensuring there is adequate capacity available to meet demand. Production Planning describes how the required energy demand is to be met on an hourly basis whilst maintaining least-cost dispatch within known constraints.

Generation uses a plant-aged assumption for long term planning including the Generation expansion, financial and LOPPs, however, the actual life is not determined by age but by the economic viability. Currently, 50 years for the coal fleet is used for planning purposes. The LOPP is based on a codified preventive maintenance strategy for each power station. This prescribes what maintenance interventions are required at what periodicity as well as the standard maintenance activities required. Power stations have specific requirements with respect to the numerous cyclical maintenance interventions required on a power plant.

Maintenance costs are primarily a function of the amount of maintenance and the cost of each maintenance activity. The amount of maintenance is influenced by factors such as capacity added to or removed from the system, the age of plant and maintenance activities are determined by the maintenance planning process.

17.3.1.3 Generation Maintenance Plan Implementation in FY2025

Eskom's Generation Maintenance Plan remained a dynamic, continuously evolving programme throughout FY2025, aligned to system requirements. The plan was continuously updated to accommodate changing operating environments, including plant availability, fuel constraints and slower-than-expected IPP capacity additions. While this adaptive approach supports overall system stability, it can result in deviations from stations' original philosophy maintenance schedules. The FY2025 maintenance strategy focused on balancing reliability maintenance with system adequacy to ensure security of supply while executing critical refurbishment work.

17.3.1.4 Maintenance Execution and Performance

Execution of planned maintenance improved year-on-year in FY2025. This reflects Eskom's continued commitment to restoring the reliability of our generation fleet through disciplined maintenance practices.

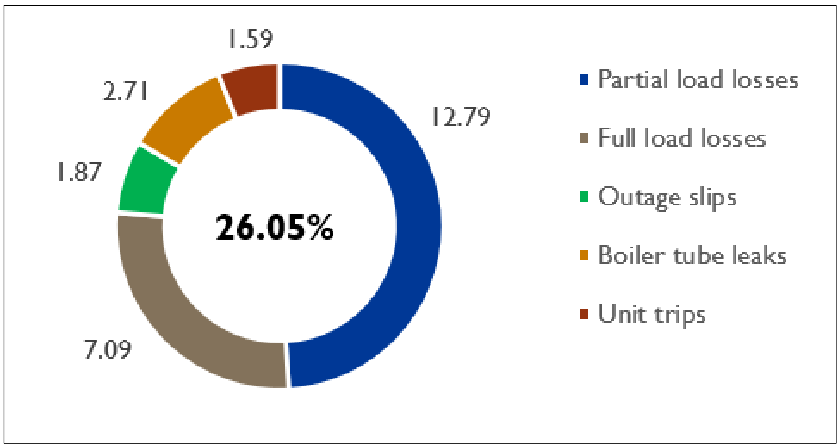
Outage planning is informed by system capacity constraints, plant-specific risk profiles, and the availability of critical spares and skilled resources. A total of 69 outages were scheduled for the year. By year end, generation had successfully completed 36 outages, 12 were in execution, 18 had been deferred to the coming year and three had been cancelled, with the required work completed under alternative outage windows. In addition to the scheduled programme, we executed 51 short-term corrective maintenance outages. These interventions were implemented to mitigate emerging risks and prevent potential availability losses, underscoring the agility of our maintenance teams in responding to dynamic plant conditions.

In recent years, outage performance and recovery plans have been hampered by the late release of funds caused by Eskom's constrained liquidity position. This had a ripple effect on outage readiness for activities such as the ordering of spares and other long-lead materials, issuing of task orders and finalising the integrated schedule. The situation improved considerably during the year due to better liquidity levels driven by financial support received under Government's debt relief programme. This situation aided decision-making in the use of cash from operations towards outage planning knowing that debt servicing is covered by the debt relief support.

17.3.1.4.1 Unplanned losses

Addressing excessive levels of unplanned unavailability remains a critical challenge, despite intensified efforts under the Generation Recovery Plan. UCLF has improved compared to the previous year, due to a reduction in both full and partial load losses. Nevertheless, persistent issues continue to drive elevated levels of UCLF.

FIGURE 6: CONTRIBUTION TO UCLF%



Average partial load losses of 5 913MW are significantly lower than the previous year (2024: 6 615MW), thereby contributing to improved system performance. Nevertheless, these losses contributed 12.79% to UCLF (2024: 14.21%), accounting for half of total unplanned losses. Outage slips also dropped significantly, contributing 1.98% to overall UCLF (2024: 3.56%), despite post-outage UCLF decreasing marginally as discussed above. Unit trip performance has deteriorated, with 699 trips during the year (2024: 593). Generation has established the Trip Reduction Forum to identify and monitor trends and significant concerns in areas with high numbers of trips; plant running outside reliable operating limits is identified to prevent avoidable trips.

The boiler tube failure rate (failures per unit per year) improved slightly to 2.31 for commercial units using a 12-month moving average (2024: 2.37), with boiler tube failures contributing 2.77% to UCLF (2024: 2.97%). The boiler tube failure rate seems to have stabilised after an upward trend over the past five years, attributable to the maintenance backlog during that period that resulted from constrained capital funding.

Four stations achieved a failure rate less than or equal to one failure per unit per year, these being Camden, Kendal, Medupi and Tutuka. Three stations recorded a failure rate between 1 and 1.8 failures per unit per year, namely Matimba, Kriel and Kusile.

17.3.1.4.2 FULL LOAD LOSSES DUE TO MAJOR INCIDENTS

Medupi Unit 4 suffered significant damage in a generator explosion in August 2021. The unit was excluded from the nominal asset base from October 2023 until 1 June 2025.

To enable the return to service of the unit until a new generator stator can be fitted during a future planned outage, a used stator from the Netherlands was installed as an interim measure. The unit was successfully synchronised to the grid on 6 July 2025, marking a major milestone in our strategic objective of achieving operational stability. Once the unit reaches full output, it will further strengthen base-load generation capacity, contributing to the stability of electricity supply and enhancing national energy security.

At Tutuka Unit 6, a fire during recommissioning in November 2023 after a planned outage delayed the unit's return. The unit was placed in extended inoperability in August 2024. The recovery plan is being executed, with progress on the manufacturing and supply of spares at 70% by the end of the financial year; installation is in the initial stages. The unit is expected to be recovered by October 2026.

Matla Unit 6 suffered an incident in December 2024 due to the rupture of a high-pressure steam pipe above the transformer. Testing and analysis to determine the root cause is still underway. Due to the long lead time for sourcing the required parts, the unit is expected to be recovered by September 2026. The unit was removed from the nominal base for reporting purposes and placed in extended inoperability from 1 July 2025.

17.3.1.4.3 KOEBERG PERFORMANCE

Koeberg Nuclear Power Station continues to operate safely and reliably, delivering the lowest marginal primary energy cost among Eskom's base-load generation assets. The station remains an indispensable contributor to South Africa's energy security and decarbonisation objectives.

Koeberg Unit 2 commenced the long-term operation (LTO) programme on 11 December 2023 to replace its three steam generators and prepare the unit for long-term operation for another 20 years. The outage was successfully completed, and the unit synchronised to the grid on 30 December 2024, completing the commissioning phase around mid-January 2025.

The steam generator replacement is expected to result in improved efficiency which will enable the units to produce more power. However, the quantum capacity increase cannot be certified until the defects monitoring period and plant optimisation efforts to enhance the units' efficiency and output have been completed. Approval to increase the maximum continuous rating (MCR) is required from internal and external governing bodies before the capacity increase can be implemented.

The NNR granted Eskom a long-term operating licence on 15 July 2024 to continue operating Koeberg Unit 1 for a further 20 years. The unit is now licensed to continue operating until July 2044, with scheduled maintenance and upgrades being performed in line with the licence requirements. These activities will be tracked as part of business-as-usual activities over the unit's extended operating life.

Activities linked to the NNR's directives for long-term operation will be performed over the remaining life of the units. These activities will be tracked to ensure adherence to the directives.

17.3.1.5 Generation Maintenance Costs for FY2025

TABLE 70: GENERATION MAINTENANCE COSTS (RM)

Gx Maintenance Opex (Rm)	Decision FY2025	Actual FY2025	Variance
Total Gx Maintenance Opex	13 910	23 205	9 295

17.3.1.6 Benchmarking Generation Maintenance Costs

In benchmarking Generation's ***maintenance spend*** *in isolation, a widely used international approach of measuring an entity's maintenance spend relative to the underlying assets' new replacement cost was considered. This is an accepted benchmark measure advocated by leading maintenance bodies (including the Society of Maintenance Reliability Professionals, SMRP in the United States) and being used by other maintenance intensive organisations in the local industry.*

Under-maintaining an asset results in lost performance whilst excessive spending results in waste (inefficiency). ***According to SMRP the optimum range of maintenance spend relative to the asset replacement cost is between 1.8% and 3%. The specialist maintenance advisory firm, Life Cycle Engineering uses a range of between 1.75% and 2.5% (with the range of the data population they have encountered being between 1% and 6%)****.*

FIGURE 7: INT APPROACH OF MEASURING THE EFFICIENCY OF A UTILITY'S MAINTENANCE SPEND

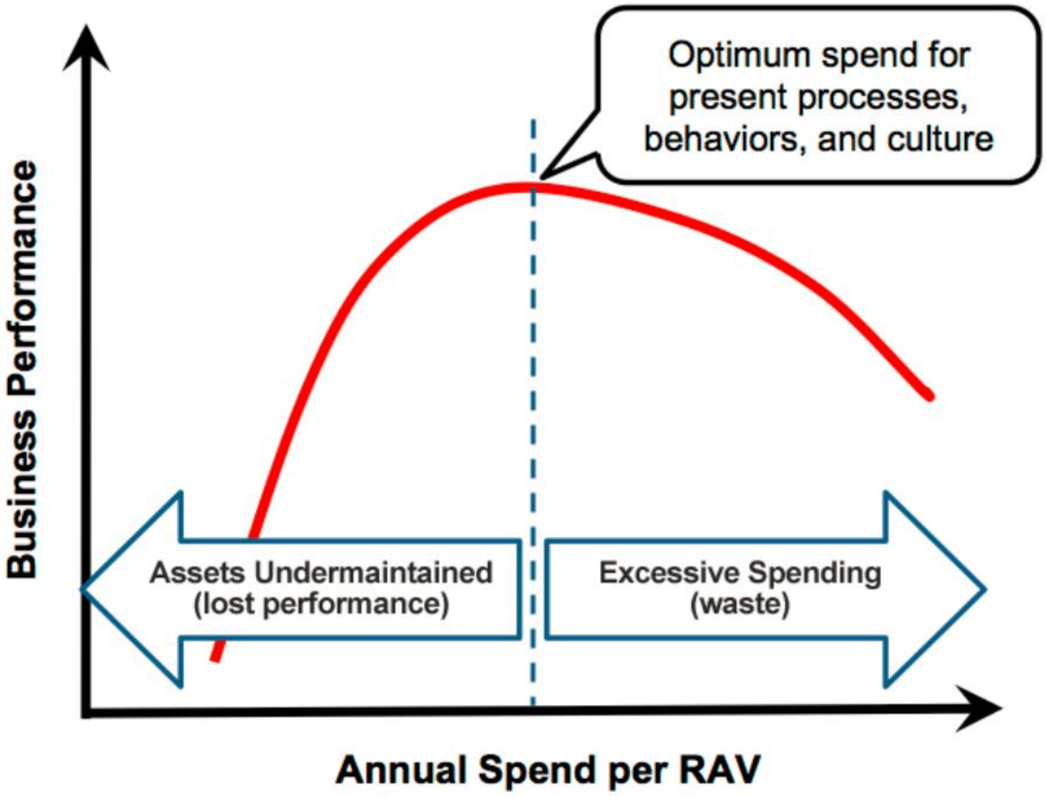
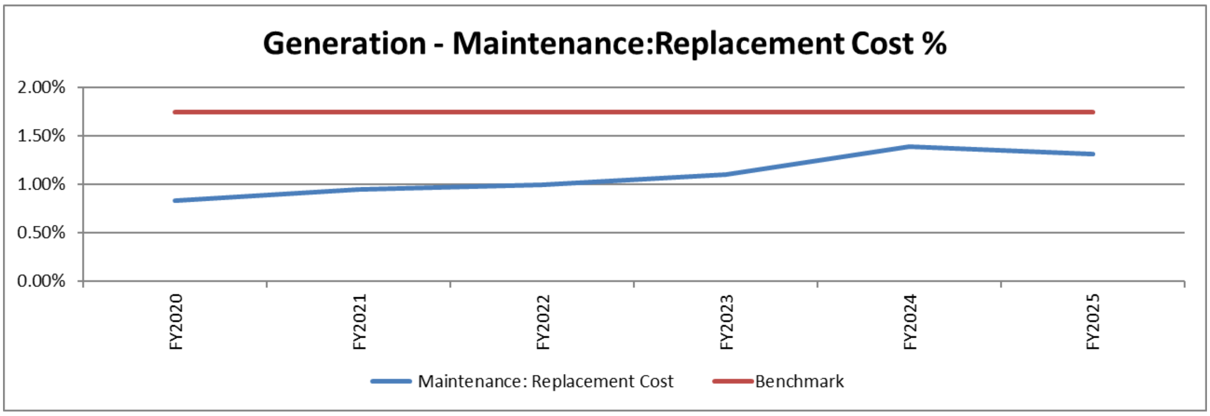


FIGURE 8: GENERATION MAINTENANCE REPLACEMENT COST (%)



How does Generation compare relative to this benchmark?

This benchmark indicates that Generation's maintenance spend is below the lower boundary. and serves to further highlight the reasonability of Generation's Maintenance spend.

17.3.1.7 Observations

In summary, FY2025 marked a turning point for Eskom's generation maintenance execution. The maintenance activities undertaken during the year were instrumental in restoring operational reliability across the Eskom fleet. Improved planning discipline, higher outage readiness, and effective execution of reliability maintenance contributed to a stable generation fleet and a sharp reduction in loadshedding. Eskom achieved measurable performance gains, reduced dependence on emergency generation, and strengthened security of supply for South Africa. The continuation of these maintenance programmes remains essential to sustaining these improvements and further enhancing system resilience in FY2026 and beyond.

17.3.2 NTCSA Maintenance cost

TABLE 71: TRANSMISSION MAINTENANCE COSTS (RM)

NTCSA Maintenance costs	Decision FY2025	Actual FY2025	Variance
Servitude Maintenance	195	240	46
Line Maintenance	215	239	25
Primary Plant Maintenance	229	254	26
Secondary Plant Maintenance	65	100	35
Equipment & Spares	40	38	(1)
Rotek (Transformer & Logistics)	351	437	86
Other	23	55	31
Total	**1 117**	**1 364**	**247**

NTCSA develops and executes maintenance plans to ensure sustainability and reliability of supply with due consideration to statutory and regulatory requirements. The maintenance cost is driven by requirements of the maintenance standards, the size of the network, the condition and performance of assets, historic spend and inflation. As more assets are added to the network, the workload and cost increases.

The maintenance variance of R247m compared to the MYPD 5 decision of R1 117m (22% variance) is mainly attributed to major transformer, line and servitude maintenance that took place in FY2025. The transmission plant is ageing, which adversely affects system reliability and necessitates sustained and intensified intervention. Key improvement initiatives focus on effective vegetation management, line-fault performance, plant availability, restoration response, and human performance. In addition, continued emphasis is placed on replacing poor-condition assets, maintaining high levels of maintenance execution, and strengthening risk management during project delivery and outage scheduling and execution.

17.3.3 Distribution Maintenance cost

TABLE 72: DISTRIBUTION MAINTENANCE COSTS (RM)

Dx Maintenance cost	Decision FY2025	Actual FY2025	Variance
Planned	3 152	2 301	(851)
Unplanned	2 579	2 977	398
Total Maintenance	**5731**	**5 277**	**(454)**

The maintenance cost variance is favourable R457m for the benefit of customers. This variance was mainly due to constraint from delays in finalising contracts, shortages or late delivery of materials, and the postponement of planned outages caused by theft and vandalism. Severe weather across the country also further disrupted maintenance work.

Key drivers for the Distribution maintenance expenditure include:

- **Network performance:** to ensure adequate maintenance is completed for the uninterrupted supply of electricity to the customer and secure revenue streams. Adequate maintenance spend will ensure that the network performs as per the design base with minimal technical losses.
- **Quality of service to customer**: adequate maintenance affords the ability to deliver energy to customer on demand at the right voltage level as defined in National Regulated Standards.
- **Growing network and customer base:** The network infrastructure grows with an increase in the customer base of more than 100 000 customers annually. This increases the maintenance requirements in both preventative and corrective (fault) environments.
- **Sustainability of network infrastructure:** The ageing network infrastructure results in further maintenance requirements. Limited previous capital investment led to potential sub-optimal performance and sustainability of network. This is now being addressed.
- **Environmental and safety consideration:** To ensure safe operations of network with a minimum impact to the environment. The magnitude of theft and vandalism on our networks are increasing at a large scale while creating greater safety risk to life and equipment.

17.4 Other Operating Costs

Operating costs include all costs involved in the day-to-day running of the business. Eskom is applying for other costs variance of R8 887m, as shown in the table below. This amount includes the three regulated businesses, namely Generation, Transmission and Distribution as well as IDM and SAE.

The MYPD 5 Revenue decision for FY2025 of R8 522m included a Generation once-off credit adjustment of R4bn and a Distribution translation error of approximately R1bn before the NERSA revenue determination analysis started. This was similar to the approach for FY2024.

In the FY2023 RCA RfD NERSA corrected the base by taking Eskom’s business model into account reflecting the true cost base of the licensees. NERSA considered all elements when it assessed the application for other operating costs before the final determination was made. It is expected that NERSA will apply the same approach in the analysis for subsequent years.

TABLE 73: SUMMARY OF OTHER OPERATING COSTS (RM)

Other Opex summary (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Generation		14 057		(2 387)	
Transmission	Eskom level	(43)	Eskom level	1 855	Eskom level
Distribution		5 490		(7)	
Total GTD	**8 523**	**19 504**	**10 981**	**(539)**	**10 442**
SAE	0	3	3	-	3
IDM	0	43	43	-	43
Corporate services	4 168	4 136	(32)	(1 569)	(1 601)
Grand Total	**12 691**	**23 686**	**10 995**	**(2 108)**	**8 887**

17.4.1 Generation Other Opex in FY2025

The NERSA MYPD5 Reasons for Decision did not apportion its decision per licensee for "Other Opex" costs. In the absence of such apportionment, the RCA motivation will be based on the prudency of the actual expenditure.

Eskom applied for a normalised Generation other opex of R8 633m. However, the collective revenue decision for Generation, Transmission and Distribution other opex was determined at R8 522m. This places Eskom in an unsustainable situation. NERSA incorrectly accounted for the abnormal expense as a once-off credit adjustment of R4bn. This resulted in an artificially low unsustainable other opex decision for Generation. It would have been correct to phase-in the recovery over a 10-year period. This was an optimal approach decided by NERSA for a similar situation in FY2019.

The breakdown of Generation Other Opex is shown in the table below.

TABLE 74: GENERATION OTHER OPEX (RM)

Gx Other Opex (Rm)	Application FY2025	Decision FY2025	Actual FY2025	Variance
Net Insurance Expense	3 378		4 555	
Other General Expenses	206		5 837	
Office and Site Operation Costs	1 407		2 082	
Materials Expense	884		1 456	
Contractor Costs	2 872		1 392	
Electricity Cost	1 110		1 065	
Operating, Lease, Consulting & Travel	659	Eskom level	743	Eskom level
Recovery Postings	(1 857)		182	
Environmental expenses	474		275	
Decommissioning Expenses	(3 618)		(2 517)	
Secondary Account Capitalisations	(253)		(1 013)	
Total Generation Other Opex	**5 261**		**14 057**	
* RCA Adjustment	-	-	(2 387)	-
Total Other Opex for RCA Purposes	5 261	Eskom level	**11 670**	Eskom level

*** Note:** Adjustment relates mainly to inventory which could not be accounted for after physical stock counts and reversal of the write-off of Majuba Rail cost. This does not form part of the RCA balance.

It should be noted that the main cost drivers of Other Opex represents costs for the day-to-day operational requirements of the business and are thus necessary.

17.4.1.1 Contractor Costs

Contractor costs constitute amounts paid to external service providers mainly for civil, design services (engineering related), drilling services, electrical services and ash handling. These are essential costs in reference to on-going contractual commitments.

17.4.1.2 Decommissioning Expenses

Changes in the measurement of an existing decommissioning liability that results from changes in the estimated timing or amount of the outflow of resources embodying economic benefits required to settle the obligation, or a change in the discount rate shall be accounted for as per below.

If the related asset is measured using the cost model:

a. Subject to 'b', changes in the liability shall be added to or deducted from the cost of the related asset in the current period.
b. The amount deducted from the cost of the asset shall not exceed its carrying amount. If a decrease in the liability exceeds the carrying amount of the asset, the excess shall be recognised immediately in profit or loss.

17.4.1.3 Environmental Expenses

These are essential costs incurred in cleaning up the environment, waste management and removal from site and monthly analysis of water and effluent.

17.4.1.4 Internal Electricity Costs

Some power stations may consume energy at Station Transformers for the purposes of auxiliary supply and other supply requirements. This energy is purchased from Eskom Distribution through the customer billing system. This cost type is volume and price driven.

17.4.1.5 Materials Expense

This amount represents the costs of stores material that has been transferred from inventory stores for the period. Examples include mill balls, lubricants, gases and chemicals used in plant operations.

17.4.1.6 Net Insurance Expense

Net insurance expense represents the Insurance Premiums paid to Eskom Insurance Management Services as well as Insurance Write-Offs.

Factors that influence the insurance premium include:

- Insurance claim trends or loss ratio performance;
- Value of the insurance excess;
- Increased asset base;
- New build programme;
- Re-insurance costs by external insurance markets;
- Increase in insured asset values (cover is generally based on replacement value, not market value);
- Risk management efforts by the insured to minimise exposure.

Maintenance and asset renewal are good measures to treat the risk of failures due to ageing plant. The net insurance expense could increase considering the ageing generation fleet.

17.4.1.7 Office and Site Operations Costs

This constitutes mainly of the following components:

- Cleaning Materials and Services for the plant and offices: Cost of cleaning services rendered by external parties including purchases of cleaning materials.
- Licence levies for Water, National Nuclear Regulator, NERSA, etc.
- IT Costs: Amounts paid to external service providers for IT-related costs. Examples include services like data mining, print services, data charges, advice on firewall security, WAN link rental costs, email archiving contract, IT LAN cabling, or in the case of the current over-arching outsourced IT service provider.
- Horticultural Services
- Occupational Health Services
- Security Services
- Safety Gear and Equipment

17.4.1.8 Operating Lease, Consulting and Travel Costs

Travel expenses include both local and international business travels undertaken by employees in the operational course of business or to attend training and meetings on behalf of Eskom.

Fleet Management Services (FMS) is a single, centrally managed entity and is established within the Eskom Shared Services Division to take ownership of the total Eskom Fleet and integrate the total fleet management process within Eskom. Fleet Management Services operates on a break-even basis and recovers costs. These are further differentiated per main vehicle category to account for differing rates at which these vehicles are billed at. The purpose of the charge is to recover the cost of providing fleet services based on the pricing structure in line with regulatory requirements. The pricing structure for the various products provided are reflective of the real cost of providing the service.

17.4.1.9 Other General Expenses

Other General Expenses include the following components: Production plant service cost, Servitude service contractor, Facility service costs, Equipment spares and repairs service contractor, legal fees, printing, stationery and office, telephones and cellphones, facilities cost, Facilities cost - water and electricity, Marketing expenses, Insurance repairs, Low value assets written off on purchase and sundry other expenses.

17.4.1.10 Recovery Postings

This represents costs recovered/or not under other cost elements.

17.4.2 NTCSA Other Opex

TABLE 75: TRANSMISSION OTHER OPERATING EXPENSES (RM)

NTCSA: Other Operating costs	Application FY2025	Decision FY2025	Actual FY2025
Insurance Premiums	301	Eskom Level	597
Security Expenses	170		219
Telecommunications	102		71
IT Expenses	98		216
Travel & Fleet Expenses	107		126
Consulting and Legal Costs	52		58
Facilities	64		94
Leases	36		27
Internal Electricity Costs	31		22
Other	(66)		(146)
Operating costs before Abnormal costs	**895**	**Eskom Level**	**1 284**
Abnormal costs	-		(1 328)
Total Operating costs after Abnormal costs	**895**	**Eskom Level**	**(43)**
*RCA Adjustment	-	-	1 855
Total Other opex for RCA purposes	**-**	**Eskom Level**	**1 812**

Note: Recovery by service functions (Telecommunication and Aviation).

In FY2025 operating costs (excluding abnormal costs) is 36% more than MYPD 5 application largely owing to an increase in insurance costs, security expenses and IT related costs which are partly offset by costs recoveries and decrease in telecommunications costs.

Net Abnormal costs (credit) of R1 328m is attributable to the following:

- R 2 450m (credit) - The amortisation of the financial guarantee liability in FY2025 was recognised in profit or loss. NTCSA acts as a guarantor on the remaining liabilities of Eskom owed to creditors at the date of the demerger, the guarantees were provided to the creditors to facilitate the demerger of Transmission division from Eskom into the NTCSA.

- R 527m is attributable to loss incurred due to disposal or writing-off of several projects and assets. These include the cancellation of the Mulilo Total Coega project, scrapping of assets related to the Duvha/Kusile Integration Project and line deviations caused by sinkholes, and the loss of a 400 kVA transformer at Komsberg due to an explosion. Additional disposals involved the scrapping of telecommunication assets as part of an asset purification exercise, removal of equipment at Hydra and Acacia sub-stations.
- The R 595m is an expected credit loss on financial assets resulting from the impairment of the financial assets as per IFRS 9 on Financial Instruments. The Liquidity and Cash Management Agreement (LCMA) between Eskom and NTCSA stipulates that Eskom will manage NTCSA's Treasury requirements which means cash balances that are held in NTCSA's bank accounts are swept into the Eskom Treasury accounts daily. It is assessed that these balances cannot be classified as NTCSA's cash and cash equivalent as per IAS 7 (Cash flows), instead be recognised in the current account as Term Loan Receivables in terms of IFRS 9. IFRS 9 requires that impairments should be recognised based on an Expected Credit Loss (ECL) model. To comply with the requirements, an ECL percentage is applied to the loan receivable each reporting period.

RCA Adjustments:

- All valuation adjustments for financial assets made for IFRS purposes are excluded for RCA purposes. i.e the financial guarantee expense and the expected credit loss adjustments.

Other operating expenses (excluding abnormal costs) are attributable to the following items:

- **Insurance Premiums** – ESCAP insurance premiums are mainly based on the size of the declared assets and employee headcount. The increase in comparison to the MYPD 5 application is due to inflation, the impact of claims incurred and the change in the asset valuation methodology as well as the 6% growth in NTCSA's asset base (R80bn in FY2024 to R85bn in F2025).
- **Security** – The costs of FY2025 security increased by 28% in comparison to FY2024.

TABLE 76: TRANSMISSION SECURITY INCIDENTS

Type of Security Incident	Number of Security Incidents	
	FY2025	FY2024
Theft of Conductors, Cables, Batteries	145	54
Tower member theft	22	15
Malicious Damage To Property	85	59
Armed Robbery	23	25
Business burglary, Common theft and Housebreaking	65	151
Other	35	47
Total	**375**	**351**

During FY2025, NTCSA recorded 375 security incidents, reflecting a 6.4% increase compared to the previous year. This increase in the number and severity of security incidents required a need to improve the security situation to safeguard assets and employees. Annual crime statistics show a 6.4% increase in crime incidents and a 57% decrease in estimated financial losses compared to FY2024. During FY2025, a total of 68 arrests were made, with 52 resulting from intelligence-driven and disruptive operations, and 16 occurring at NTCSA business units.

A Security Action Plan was developed, and it comprised of key deliverables that are aimed at dealing with identified security threats within the organisation. This includes enhanced security measures, such as intrusion detection technology, disruption operations, and successful arrests, which have helped to reduce further increase in security incidents.

Most crime incidents can be attributed to various factors, including the remote location of sites, ageing and outdated security infrastructure, and the growing insider threat involving NTCSA personnel and security contractors. Overhead conductor theft remains a challenge due to the extensive 33,000 km NTCSA network, making it difficult for policing. To address these security challenges, various remedial measures are being implemented. These include vibration sensors on lines, aerial surveillance using drones, and vetting NTCSA personnel for improved integrity management.

Looking ahead, NTCSA will focus on accelerating the implementation of the National Security Capex Project, advancing IoT-enabled monitoring solutions and aerial surveillance capabilities, and strengthening operational capacity through targeted recruitment of security personnel. In parallel, intensified enforcement actions against illegal scrap metal trading will remain a priority. These initiatives, supported by sustained collaboration with law enforcement agencies and enhanced stakeholder engagement, are designed to reinforce NTCSA's security posture and reduce risks to critical infrastructure.

- **Telecommunication costs** are primarily due to the following services: Operational SCADA information for circuit visibility / controllability in the control room, control room communication, enabling remote interrogation of digital fault recorders, enabling remote downloading of revenue meters at NTCSA boundaries, enabling communication with Wide Area Monitoring devices.
- **Information Technology (IT) expenses** are largely driven by the number of users and applications in operation. During FY2025, NTCSA's employee complement increased by 412, contributing to higher IT costs. Charges for infrastructure services, end-user computing, and help-desk support are based on monthly volumes of the contracted service items. Software annual licensing and support costs increased as these expenses shifted from being treated

as overheads to direct cost allocations, with charges now applied proportionally based on the number of personal computer users. In addition, costs rose due to the implementation of enhanced security solutions following a change in service provider.

- **Consulting costs** have increased compared to the revenue application forecasts. It is Eskom's policy to appoint external service providers only in circumstances where such skills are not available within the organisation or where it is prudent to elicit advice/services of an independent body. Consulting costs includes:
  - Legal services and support that are required for servitude acquisition negotiations and disputes that arise with the landowners as well as registrations of acquired servitudes.
  - Independent professional service providers to undertake certain tasks in acquiring property/servitude rights. This includes Geotech studies, town planning assessments, visual/social impact assessments, property valuation and land surveying.
  - Designing services fees to assist with PTMC and engineering designs.
  - Legal and consulting costs for unbundling.

The procurement of the professional services is conducted by Procurement department's Panel Control Committees. An open tender is awarded by allocating work on a rotational basis to the companies on the panel (where agreed fixed rates exist). If there are no fixed prices, a tender is issued to the companies on the panel that have previously been approved based on their technical and financial capability.

- **Fleet & Travel** – this includes both the local and international business travel undertaken by employees in the operational course of business as well as to attend training and meetings on behalf of Eskom. There has been a slight increase in these costs due to a combination of inflation and increase in maintenance.

- **Facilities** – These costs relate to the servicing and maintenance of buildings and facilities. They include expenses for rates and taxes, municipal services, maintenance, repairs, cleaning services, and other related items. The increase in Facilities costs is primarily due to NTCSA now bearing the full cost of electricity usage and municipal rates and taxes. In previous financial years, most of these costs were covered by Eskom Real Estate or the Distribution Division, which accommodated Transmission employees. However, following NTCSA's separation from Eskom, the company is now responsible for these expenses through intercompany charges from Eskom and direct payments to municipalities. This change also includes costs for alternative accommodation for employees, as the Distribution Division can no longer provide space for NTCSA staff.

- **Leases** – this is primarily for the rental of office space, aircraft hangars, telecommunication infrastructure site sharing and storage areas where Eskom does not own sufficient facilities.
- **Other** – The other expense includes impairments, Telecom plant maintenance and other sundry expenses which is offset by recoveries by Eskom Aviation and Eskom Telecommunication which provide services to NTCSA and other divisions within Eskom.

17.4.3 Distribution Other Opex

Compared to the NERSA application the other costs that increased were due materials and contractors. Fleet costs demonstrating increased operational activities resulting in an indicative R1 900m variance. The higher costs were partially offset by a substantial underspend in information technology, facility costs and vending agents' commissions.

TABLE 77: DISTRIBUTION OTHER OPERATING COST – RM

Dx Other Costs	Application FY2025	Actual FY2025
Insurance	1 774	1 844
Security cost	609	466
Information technology costs	517	188
Fleet cost	66	1 267
Facilities cost	766	287
Telecoms	148	29
Material and Contractors	319	228
Customer related		
– Vending Commission	637	248
– Customer billing related expenses	135	108
– Legal Fees & Debt Collection	37	61
– Wheeling cost	63	167
– Bank Related Costs	25	17
– Reconfigure Prepayment meters	81	19
– Business related expenses	80	560
Total Other Opex cost	**5 257**	**5 490**
*RCA Adjustment	-	(7)
Total for RCA Purposes	**5 257**	**5 483**

Further, for the respective other costs the variances were:

- **Insurance:** The business must ensure that there is adequate insurance cover in place to manage its increasing asset base and exposure against insurable incidents such as natural occurrence, theft, vandalism and public liability claims. The market prices for the premium are hugely driven by replacement cost of assets and past claims history. Insurance covers risk beyond the maximum tolerance levels for the business.
- **Security:** Many of the Distribution sites are designated national key points, which in terms of legislation require these assets and people to be safe guarded. There has been an increase in theft and vandalism of equipment which warrants the need to safeguard assets

for continuity of operations. Security related activities are preventative in nature to safeguard assets, property and employees.

- **Information technology costs:** Information management systems are key to the current and future business operations to support improvement in efficiency, productivity and decision making. The vastness and complexity of network infrastructure require a number of integrated management systems for network management, outages, dispatching and customer interface and interaction. The information systems enable optimal and efficient network operating, optimal customer billing and revenue collection. The changing customer needs necessitate investment in digital platforms which require continued maintenance to support delivery of the desired customer experience and service delivery.
- **Fleet and travel cost:** The Distribution network infrastructure footprint is across South Africa mainly in deep rural areas. Employees are required to extensively travel to provide a service all customers. This involves operating, maintaining and repairing networks to comply with regulatory and service standards. Key to the cost is employee recoveries of kilometres travelled for business related activities and associated subsistence allowances. The employees are reimbursed at the SARS travel rates and the Eskom policy aligned to National Treasury Directive on cost containment.
- **Facility cost:** The geographical customer spread across the country, accessibility, convenience to the customer and the business value proposition to meet customer expectations required the establishment and maintenance of customer network centres, hubs and local offices in close proximity to the customer locations. These properties are either owned or leased, and the business carries all associated service costs. The driver of the facility cost relates to rentals, water and lights, rates and taxes and maintenance.
- **Vending commission:** The prepaid customer base is served through a network of vending agents located in close proximity through various platforms for ease of access for the customer. Vending commissions are costs paid to the agents that sell electricity on behalf of Eskom.
- **Customer billing and meter reading expenses:** Billed customer meters are read in intervals through meter reading agents to ensure accurate and timeous billing for energy consumed. The meter reading agents are compensated for the actual number of customer meters read at a predetermined rate. The business also incurs costs for the generation of the customer bill and the distribution thereof.
- **Wheeling:** Wheeling cost is the transportation of electric energy from within an electrical grid to an electrical load outside the grid boundaries.
- **Arrear debt:** Eskom does not include the *total* arrear debt for the purposes of the RCA balance determination.

17.5 Other Income

TABLE 78: SUMMARY OF OTHER INCOME (RM)

Other Income	Decision FY2025	Actuals FY2025	Variance
Generation	(470)	(688)	(218)
NTCSA	(120)	(617)	(496)
Distribution	(532)	(648)	(115)
SAE	-	(0)	(0)
IDM	(1)	-	1
Corporate services	(110)	-	110
Total	**(1 233)**	**(1 953)**	**(719)**

In the course of Eskom operations in FY2025, Eskom generated total other income of R1 953m which is shown in the table above.

17.5.1 Generation Other Income

Other income consists of the following categories: Insurance income, operating lease income, sale of scrap and sundry income.

Generation Other income is shown in the table below.

TABLE 79: GENERATION OTHER INCOME (RM)

Gx Other Income (Rm)	Decision FY2025	Actual FY2025	Variance
Insurance Income		(213)	
Operating Lease Income		(105)	
Sundry Income		(370)	
Total	**(470)**	**(688)**	**(218)**

17.5.2 Transmission Other Income

TABLE 80: TRANSMISSION OTHER INCOME (RM)

NTCSA Other Income	Decision FY2025	Actual FY2025	Variance
Insurance Proceeds		(220)	
Lease income		(57)	
Sundry Income		(339)	
Total	**(120)**	**(617)**	**(496)**

Other income was R617m compared to the NERSA determination of R120m resulting in a R496m variance.

- **Insurance proceeds** - are not planned for or envisaged in the MYPD application as the pay-outs on insurance claims cannot be determined upfront.
- **Operating lease and Sundry income** - encompass leasing, co-sharing, and maintenance services contracts with various external customers for our fibre, radio sites, and

telecommunication network and equipment. The notable increase in sundry income is primarily due to the reinstatement of contracts with Broad Band Infraco (BBI), the largest external customer for telecommunications and fibre network services. These contracts were previously terminated and therefore excluded in the MYPD 5 revenue application. Following a court ruling, the contracts have been reinstated which has resulted in a substantial increase in sundry income compared to MYPD 5 decision.

17.5.3 Distribution Other Income

TABLE 81: DISTRIBUTION OTHER INCOME (RM)

Dx Other Income (Rm)	Decision FY2025	Actual FY2025	Actual - Decision
Insurance proceeds/recovery		(444)	
Reconnection fees		-	
Business sales		-	
Recoverable work		-	
Operating Lease Income		(13)	
Sundry income		(191)	
Total other income	**(532)**	**(648)**	**(115)**

The key variance in Distribution other income is mainly attributed to insurance proceeds.

17.6 Corporate services

At the time of the MYPD5 Revenue Application the re-linking of line divisions was not taken into account as noted in the FY2023 RCA Application (Par. 18.7 page 144 of 159):

"In preparation for the divisionalisation or ring-fencing of Eskom, some of the operational level services which formed part of the approved spend, have been relinked to the line divisions, Generation, Transmission and Distribution. Group Technology has been relinked from a central corporate role to Generation. Hence all costs associated with these services now reside within the line division.

Services including finance, security, procurement, fleet services and revenue management within the remaining corporate functions, which are considered to be better managed within the licensees, have also been relinked."

It is important to note that this will have a knock-on effect throughout the MYPD 5 period (FY2023 – FY2025).

TABLE 82: CORPORATE SERVICES OPERATING COST (RM)

Operating costs (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Corporate employee benefits	**3 412**	**2 430**	**(982)**	**(419)**	**(1 401)**
Corporate cost excl. employee benefits	**4 168**	**4 136**	**(32)**	**(1 568)**	**(1 601)**
Other Opex	3 202	2 785	(417)	(97)	(514)

Operating costs (Rm)	Decision FY2025	Actuals FY2025	Variance	RCA adjustments	RCA FY2025
Maintenance	-	-	-	-	-
Arrear debt	-	-	-	-	-
Other income	(110)	(1 056)	(946)	-	(946)
Depreciation	332	191	(141)	-	(141)
Net finance costs	744	2 215	1 471	(1 471)	-
Total Corporate costs	**7 580**	**6 566**	**(1 014)**	**(1 988)**	**(3 002)**

The corporate division had set out to continue to adhere to the strategy of providing its services, strategic and operational, in accordance with the model mooted in its submission.

The three major categories of NERSA's determination for the corporate division comprised a determination of R3 412m for employee benefits, R3 202m for operating costs and depreciation of R332m, which totals to R6 946m. This, contrasted against actual spend for the year under review of R6 566m (which includes net impairments), results in a variance of R3 002m in favour of the consumer.

17.6.1 Corporate Employee Benefit costs

The NERSA determination on employee benefits is exactly the same as Eskom's application for employee costs and employee numbers i.e. there was no disallowance by NERSA. The table below illustrates the actuals in comparison to the NERSA decision.

TABLE 83: CORPORATE EMPLOYEE BENEFIT COSTS (RM)

Corporate Employee costs	Decision FY2025	Actual FY2025	RCA Adjustment	Variance
Employee Expenses (Rm)	3 412	2 430	(419)	(1 401)
Employee Numbers	2 717	2 401	-	316

The year-end actual employee number of 2 401 is 316 employees less than the determination. This is mainly due to the higher staff turnover and the challenge with respect to attracting and retaining suitably qualified staff.

Overall, employee benefit costs have a variance of R1 401m for the benefit of the consumer. This is due, in part, to the same reason stated above. Included in Group Finance is a re-determination of the pension benefit obligation with respect to the whole organisation that resulted in a variance of R1bn for the benefit of Eskom. This variance has been ring-fenced at a corporate level for the 2025 financial year.

An adjustment of R419m relates to Eskom not including performance bonus payments in the RCA application.

17.6.2 Depreciation

A variance in corporate depreciation for the benefit of the consumer of R141m is primarily due to delays in hardware procurement and capital project execution resulting in delays in transferring planned assets under construction to commercial operation.

17.6.3 Corporate Other Opex

Other operating expenses has a variance of R417m. The variance is due mainly to the following. The Eskom Academy of Learning has a variance of R227m in favour of the consumer due to significantly less inter divisional charges planned with respect to accommodation, meals and other related charges. Group Finance has a variance of R105m due to lower insurance premium and audit fees. Procurement and supply chain, Human Resources and Strategic functions have a variance of R169m due to unfilled executive vacancies, delays in projects and variances in consulting and legal costs. In addition, less travelling as well as savings achieved through a deliberate savings drive throughout corporate services contributed to the lower spend. Finance expense had a variance for benefit of Eskom, of R1 471m due to a post-retirement medical aid actuarial adjustment. This is an aspect included in certain employee conditions of service.

17.6.4 Corporate Other Income

Other income had a variance of R946m primarily due to unexpected additional dividend income of R50m, unplanned grant income from EWSETA of R74m and income from NTCSA with respect to insurance premium recoveries and other overheads of R813m by extension, the consumer.

17.6.5 Research and Development

Eskom's Research, Testing and Development (RT&D) plays an integral role in the pursuit of company objectives and strategic imperatives. RT&D provides a variety of services to the Eskom organisation including scientific and technical advice, research, testing and consulting, as well as providing strategic technical planning services and direction. The role of RT&D includes opening new technological opportunities for Eskom by providing Technical R&D support of relevant and emerging cutting-edge technologies. These technologies create synergies with different institutions (Universities and Research Institutions) in getting solutions to Technology and skills challenges facing Eskom Plants (Generation and Wires).

The RT&D Strategy for FY2025 has continued with the 60:30:10 principle to support the line functions. Where, 60% represents RT&D efforts to support Eskom Line Functions with the operational recovery initiatives; the 30% is representative of RT&D's efforts to assist with transition away from coal; and 10% is illustrative of RT&D's efforts to assist in positioning the business to be a greener and smarter utility.

The research projects are aligned to key internal stakeholders, through research roadmaps for divisional business units: Generation and Distribution; subsidiary: National Transmission Company South Africa; and external stakeholders in various fora, including the Industry Stakeholder Review that is convened annually. This is an engagement session in which RT&D gives feedback to industry stakeholders, most notably NERSA, about RT&D's research portfolio, and gets input from these stakeholders on what RT&D could be doing differently. There is also monthly review of the Research Key Performance Indicator (KPI) which forms part of the Eskom Shareholder Compact with the DEE for the research spend.

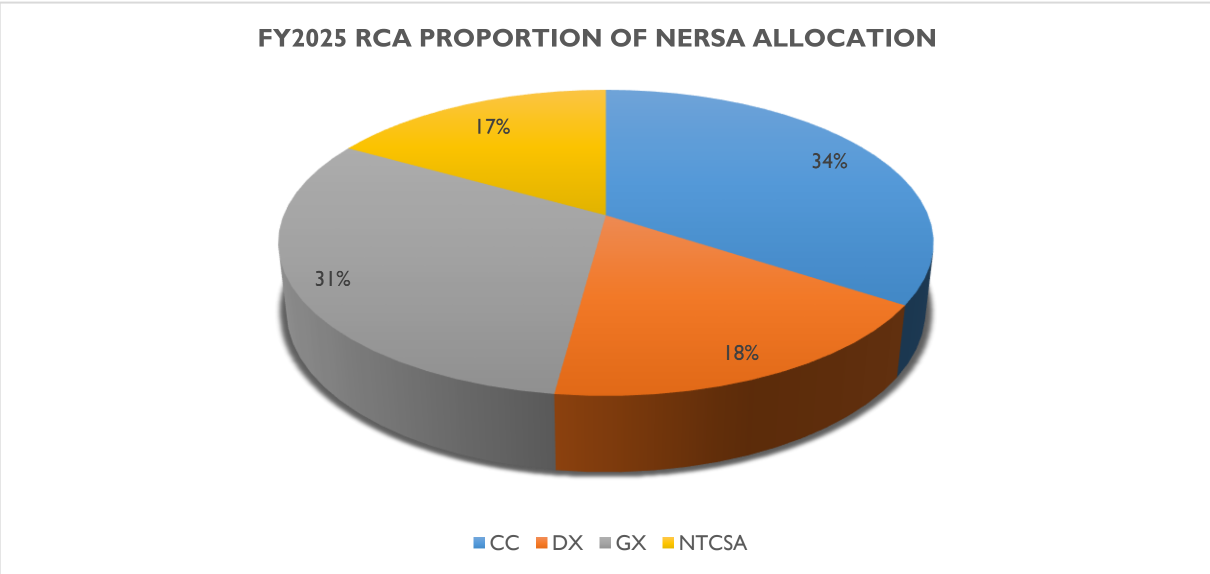
The research and development costs are included in the various elements of corporate expenditure.

TABLE 84: RESEARCH AND DEVELOPMENT COSTS (RM)

Research and Development (Rm)	Decision FY2025	Actual FY2025
Research and Development Costs	142	146

A greater emphasis has been placed on making sure that RT&D contributes quantifiable and demonstrable value to the effectiveness and efficiency to the Line Divisions. Accordingly, the projects are categorised per Line Division through the Research Advisory Committees (RACs): Generation (Gx); National Transmission Company South Africa (NTCSA); and Distribution (Dx). The following are the costs for FY2025.

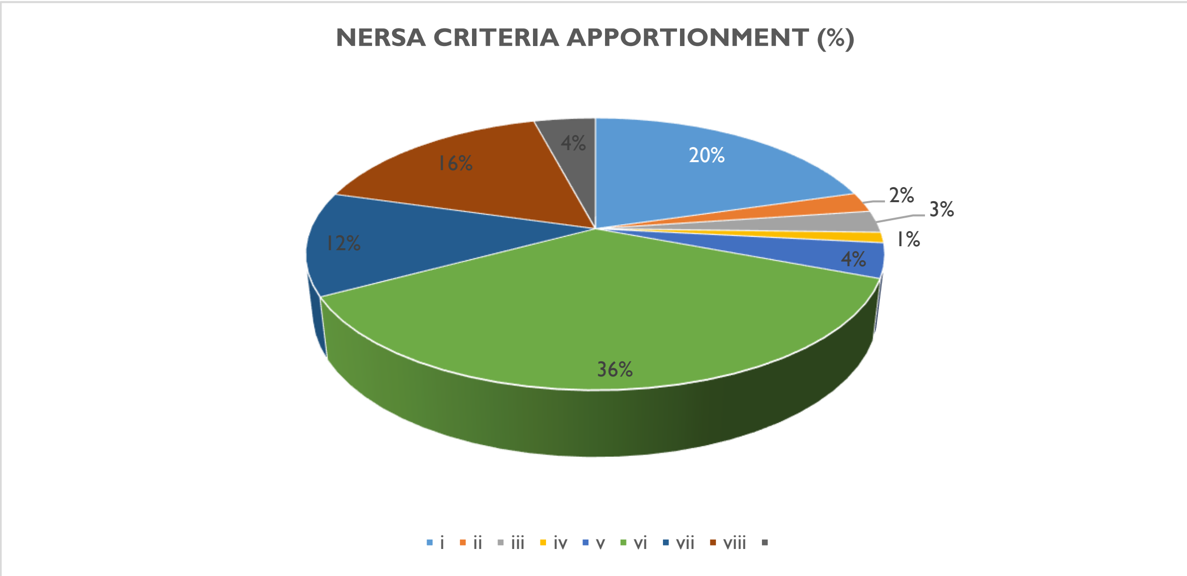
FIGURE 9: PERCENTAGE OF RESEARCH SPEND PER RESEARCH ADVISORY COMMITTEE FY2025



17.6.5.1 FY2025 Research & Development Costs against NERSA Criteria

The R146m spent on research and development costs as per the broader NERSA criteria outlined in the MYPD Methodology is as follows:

FIGURE 10 : PERCENTAGE OF RESEARCH SPEND PER NERSA CRITERIA FY2025



Where:

- **i.** Improved Efficiency
- **ii.** Extended Plant Life
- **iii.** Lower Operating Costs
- **iv.** Better Load or Power Factor
- **v.** Better Understanding of Load Behaviour
- **vi.** Build, Plan or Demo Plant - Future Build Plan
- **vii.** Developing, Designing, Selecting and Operating Renewable Energy
- **viii.** Better Usage of Water, Less pollution and Global Warming
- **ix.** Climatology

The R&D aspirations to enhance Eskom and national capabilities in energy science, technology, and engineering, provide solutions for the organisation to successfully navigate the energy challenges facing the nation, and contribute value through the research programme are all in sync with one another. Maintaining this coordination will be essential to achieving growth and economic recovery.

18 Corruption and fraud related matters

18.1 Fighting crime, fraud and corruption

Since its appointment in October 2022, one of the Board's priorities has been to restore good governance, strengthen internal controls and promote accountability. Significant attention has been given to fighting crime, fraud and corruption across the group by addressing issues stemming from weaknesses in the internal control environment and strengthening investigative capacity and consequence management processes.

18.1.1 Strengthening Eskom's response to unlawful behaviour

18.1.1.1 Key interventions by the Board

The Board has adopted a multi-pronged approach to combatting crime, fraud and corruption, centred on prevention, detection, investigation and corrective action. Preventative efforts have focused on reinforcing ethical behaviour as well as strengthening governance and controls, supported by improved systems and processes. Detection capabilities have been enhanced to allow for more effective monitoring and identification of unlawful behaviour. Eskom has also invested in building internal capacity and adequately resourcing specialist functions to investigate and respond to incidents swiftly and decisively, reinforcing a culture of accountability. Corrective actions aim to ensure that lessons from past incidents are translated into tangible improvements, including improved consequence management, supplier oversight and closer collaboration with law enforcement to recover losses and prevent recurrence. Several interventions across these areas are detailed below.

Interventions to fight crime, fraud and corruption

1 Prevention

Proactive prevention of crime, fraud and corruption

- Developed Eskom's fraud prevention plan
- Improved training across ethics, fraud awareness and procurement practices
- Enhanced compliance of declarations of interest
- Digitisation of procurement processes and introduced e-auction and e-tendering
- Monitored low-value procurement mechanisms, such as local purchase orders (LPOs), to reduce potential abuse
- Adopted National Treasury's central supplier database for informal tendering requests for quotations to reduce procurement risks
- Migrated to a new document management system to enhance document control and support audit readiness
- Introduced security vetting for directors, executives and employees in critical areas
- Conducted background checks during recruitment processes

2 Detection

Faster identification of suspicious activity

- Implemented advanced analytics to enable transaction monitoring and identify process and control weaknesses
- Improved detection capability in Eskom's online vending system (OVS)
- Enhanced Eskom's enterprise resource planning (ERP) system to improve invoicing, reconciliations and detection of ghost vending
- Improved reporting platforms and monitoring of whistle-blowing reports

3 Investigation

Effective analysis and confirmation of crime, fraud and corruption

- Established Group Investigations and Security (GIS) Department
- Established Project Management Office (PMO) to expedite backlog of cases
- Expansion of the PMO to incorporate a Rapid Response Unit
- Established war rooms in response to incidents relating to Eskom's ERP system and OVS
- Ongoing development of a single centralised repository for monitoring of all investigations
- Commissioned independent investigations by external service providers, including the Special Investigating Unit (SIU)

4 Correction

Case resolution and prevention of recurrence

- Established State Capture Task Team to implement Zondo Commission recommendations
- Reviewed policies, procedures and processes relating to supply chain management and human resources to improve consequence management
- Re-established Supplier Review Committee to enhance supplier disciplinary processes
- Strengthened partnerships with law enforcement agencies to ensure successful outcomes on Eskom's cases, including financial recoveries
- Improved employee reference flagging processes on the human resources system
- Ongoing review of lessons learned and corrective actions

Improving governance, oversight and monitoring of the end-to-end combined assurance model

- Implemented revised ethics strategy and related policies, and adopted the Board's ethics manifesto
- Executed key structural improvements to improve oversight, including separating the Audit and Risk committee and restructuring the Assurance and Forensics Department into (1) Internal Audit with the Chief Audit Executive reporting functionally to to the Audit Committee and (2) Forensics (now part of GIS) reporting to the GCE
- Strengthened Exco skills for oversight of internal controls, risk management and PFMA matters
- Established the audit recovery programme
- Commenced resourcing drives to capacitate finance, assurance and other oversight functions

18.1.1.2 Are we winning the fight?

The governance reforms and measures to safeguard the organisation by improving Eskom's capacity to prevent, detect, investigate and correct instances of crime, fraud and corruption, together with the operational and financial improvements achieved during the past year, demonstrate that we are regaining control.

While Eskom has achieved measurable progress on these fronts, and is fighting back more effectively than ever, the battle is far from over. Further efforts are required to fully sustain the recovery and foster behavioural change throughout the organisation. The Board is actively shifting the organisation from reactive and fragmented responses towards proactive and structural prevention measures, through promoting a culture of accountability, transparency and operational discipline.

18.1.1.3 Next steps

Looking ahead, measures will be focused on addressing crime and security risks, the implementation of the fraud prevention plan and enhancing investigative capabilities and consequence management processes. The establishment of a Data Analytics Centre of Excellence will enhance monitoring and analytical capabilities. The review of policies, procedures and plans will be expanded. To prevent future losses, Eskom will continue to perform revenue recovery audits, enhance detection of conflicts of interest and strengthen legal frameworks to prevent restricted suppliers from doing business with Eskom.

18.1.2 Addressing crime and security risks

18.1.2.1 Physical security

During the year, Eskom recorded 2 647 crime-related incidents which is a significant improvement from the previous year (2024: 3 732 incidents). A total of 436 arrests were made during the year (2024: 206), of which five related to employees and 88 related to contractors. These improvements can be attributed to proactive security interventions, including:

- Deployment of security technology at high-risk sites
- Disruption of criminal operations and infrastructure crime networks
- Enhanced early detection and response capabilities
- Proactive security compliance assessments and security audits at Eskom sites
- Strengthened collaboration with law enforcement agencies

Since inception of the strategy to combat coal, fuel oil and diesel theft in April 2023, over 60 arrests have been made, and more than 20 illegal coal swapping sites have been closed. We have also implemented specialised security intelligence-led investigations to monitor coal samples and coal deliveries by road between contracted mines, laboratories, rail sidings and Eskom power stations to improve coal supply integrity.

18.1.2.2 Cyber-security

Given Eskom's critical role in the country's economy and the continually evolving cyber-threat landscape, we are actively enhancing our cyber-security protection, controls and monitoring to optimise existing cyber-security capabilities and further strengthen our defensive capabilities. The information security programme has been strengthened with multiple layers of defence for enhanced protection, particularly for Eskom's OVS, which will assist in reducing potential financial losses. We have also made significant advancements to enhance cyber-security protection by replacing legacy endpoint security measures with improved software aimed at detecting advanced cyber-security threats.

18.1.3 Progress on forensic investigations

Forensic investigations

9 672 (2024: 7 132)
incidents registered through reporting channels for assessment on the forensic case management system

245 (2024: 195)
new cases registered for forensic investigation

105 (2024: 120)
forensic investigations concluded

520 (2024: 380)
cumulative cases under investigation at year end, relating to current and prior years

At year end, forensic recommendations for disciplinary action against 91 employees were yet to be finalised. A total of 66 new criminal cases were opened during the year. At year end, 247 open cases were registered with SAPS for criminal investigation, of which 227 have been referred to the Hawks in terms of PRECCA. Of these, 20 cases were at trial stage at various magistrate and specialist commercial crimes courts, and a further 63 cases have been through the criminal proceedings provided for under the Criminal Procedure Act, 1977.

18.1.4 Strengthening consequence management

During the year, disciplinary action was recommended against 82 employees, based on findings from completed forensic investigations. A total of 195 disciplinary recommendations relating to current and prior years were concluded, assisting in reducing the backlog of cases. Several interventions have been put in place to improve the effectiveness of consequence management processes. Eskom revised its employee reference flagging procedures in FY2023 to include individuals who resigned to avoid consequence management before disciplinary processes or investigations could be concluded. Individuals who have been flagged cannot be employed in Eskom for 10 years and cannot serve as an employee of a contractor on Eskom sites. A total of 84 individuals were flagged during the year (2024: 155).

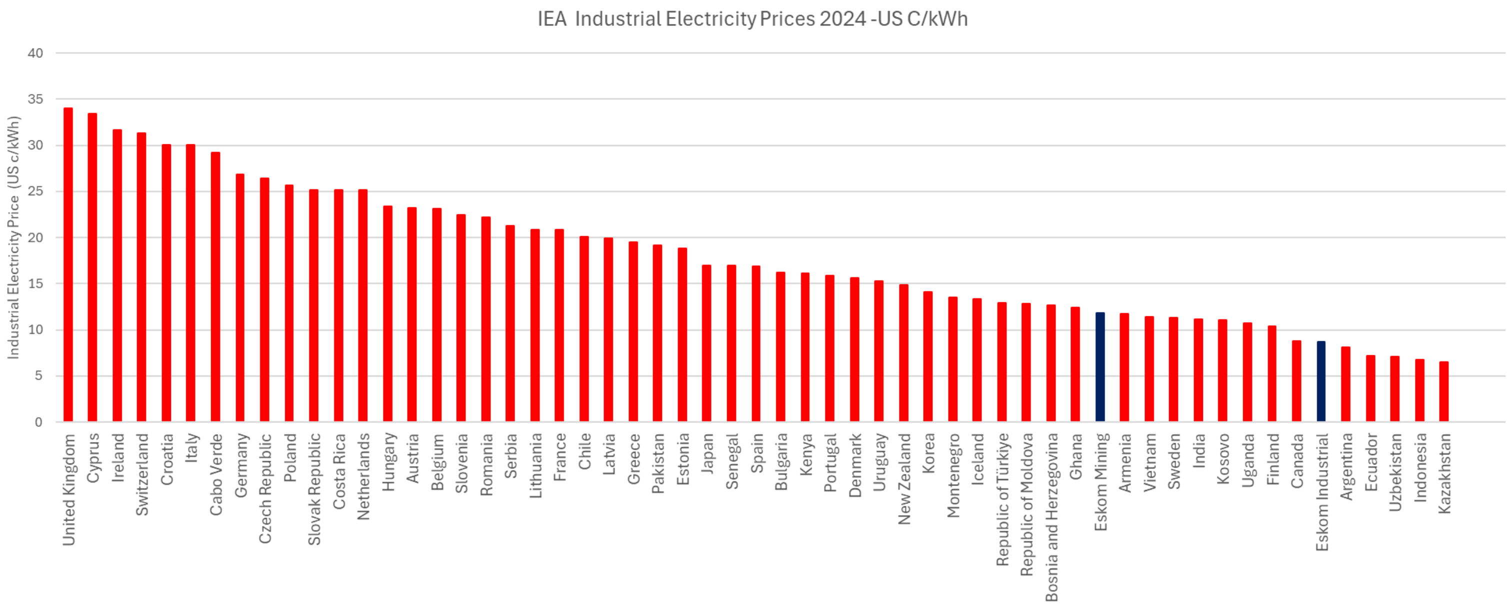
Where forensic investigations confirm that suppliers failed to declare a potential conflict of interest or engaged in misconduct and have been proven to have benefitted unduly, Eskom initiates a supplier review process. The status of 43 suppliers was considered during the year. A total of 25 suppliers received sanctions for removal from Eskom's supplier database, with referral to National Treasury for restriction. Eight suppliers received suspended sanctions, to be removed from Eskom's supplier database if any further non-compliance is committed during the suspension period. Two suppliers have had purchasing blocks implemented, pending finalisation of criminal matters, and the remaining eight suppliers were found not guilty and recommended for no further action.

19 Eskom electricity prices are still lower than many countries

Price comparisons undertaken recently indicate that Eskom electricity prices are still lower than most countries. This includes developed economies and developing economies. There is a dichotomy of electricity prices in South Africa as well. A clear distinction exists when comparing Eskom prices to those of most Municipalities. This is of concern since, over 60% of electricity customers are supplied by Municipalities. Detailed studies undertaken reflect the following comparisons.

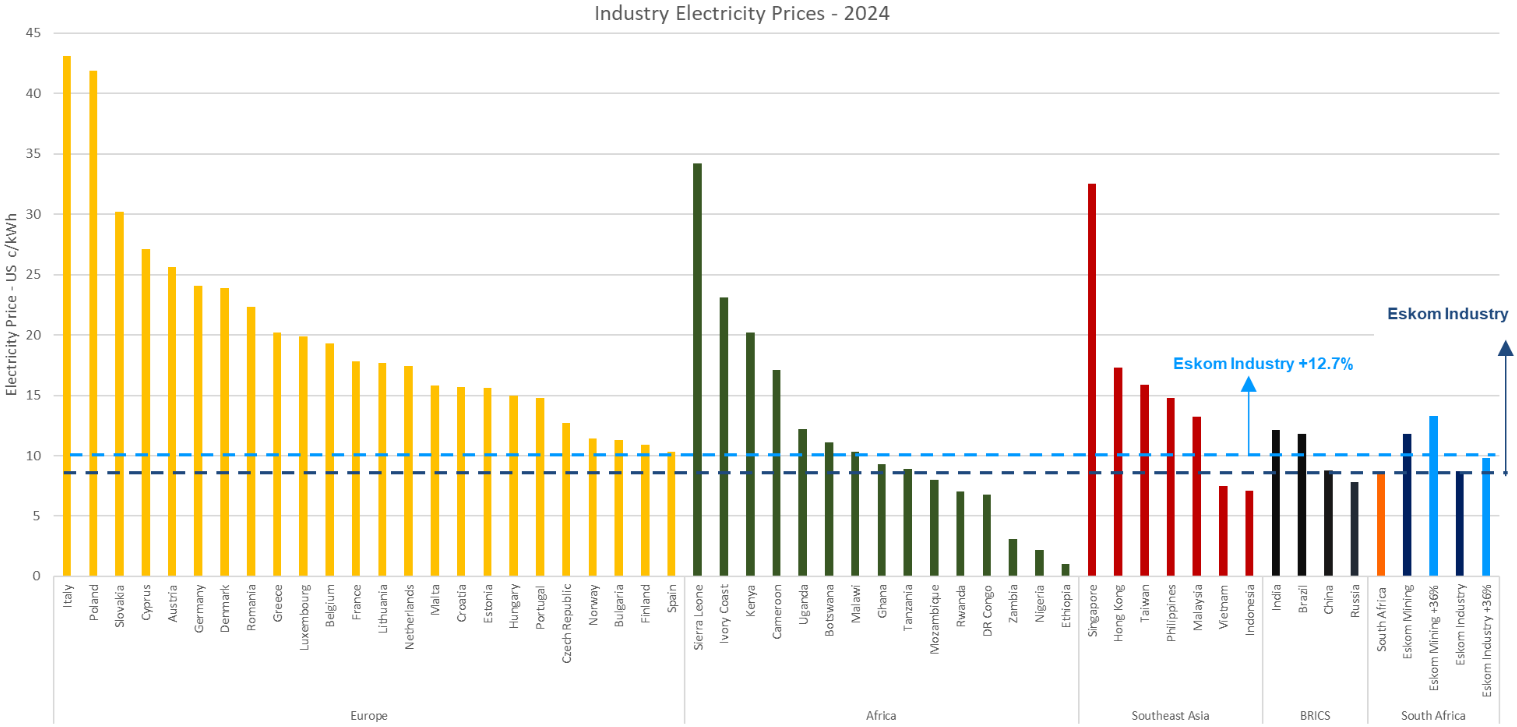
19.1 Industrial Electricity Price Comparison

FIGURE 11: IEA INDUSTRIAL ELECTRICITY PRICES 2024 – US C/KWH



The International Energy Agency (IEA) comparison above indicates that Eskom industrial and mining customer electricity prices are much lower than in many countries.

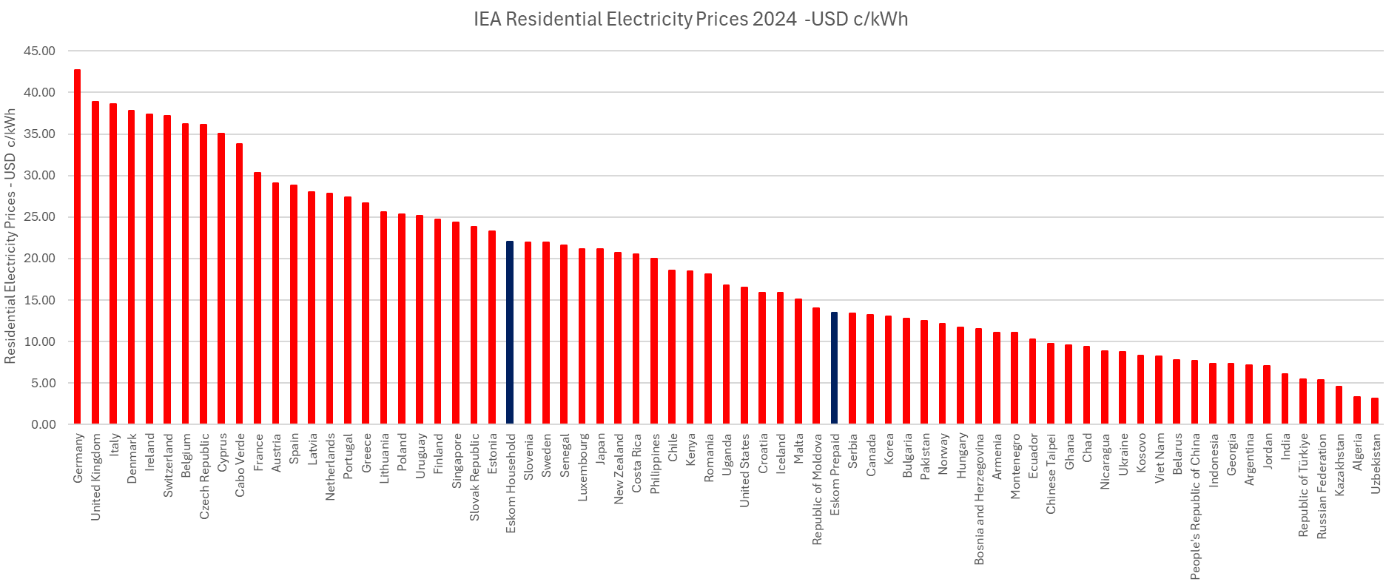
FIGURE 12: INDUSTRY ELECTRICITY PRICES - 2024



The Global Petrol price comparison above also indicates that Eskom electricity prices are much lower than in many countries. This comparison is with many continents. The 12.74% price increase still indicates that the Eskom prices are relatively low.

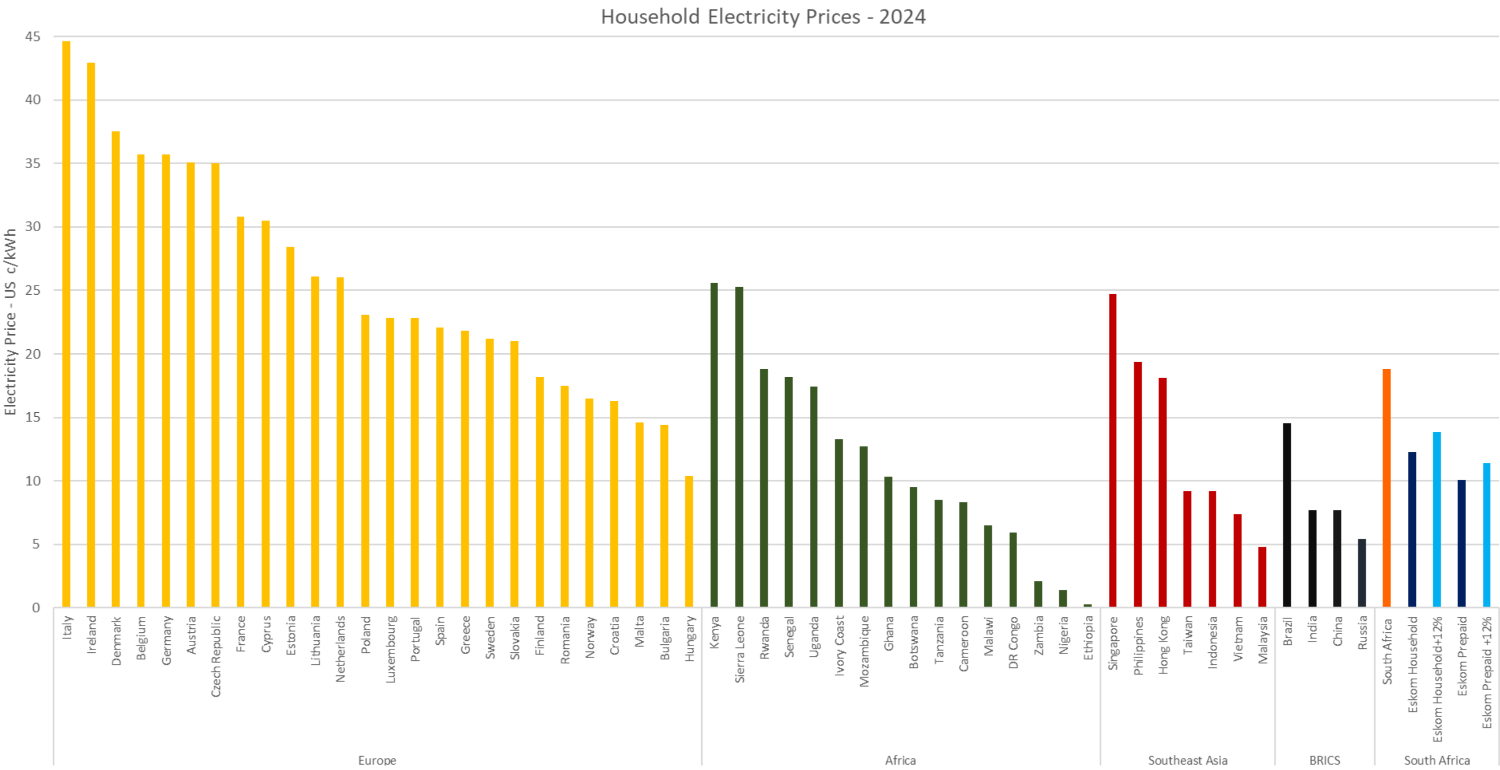
19.2 Residential Price Comparison

FIGURE 13: IEA RESIDENTIAL ELECTRICITY PRICES 2024 – USD C/KWH



The International Energy Agency (IEA) comparison above indicates that Eskom residential customer electricity prices are relatively lower than in many countries.

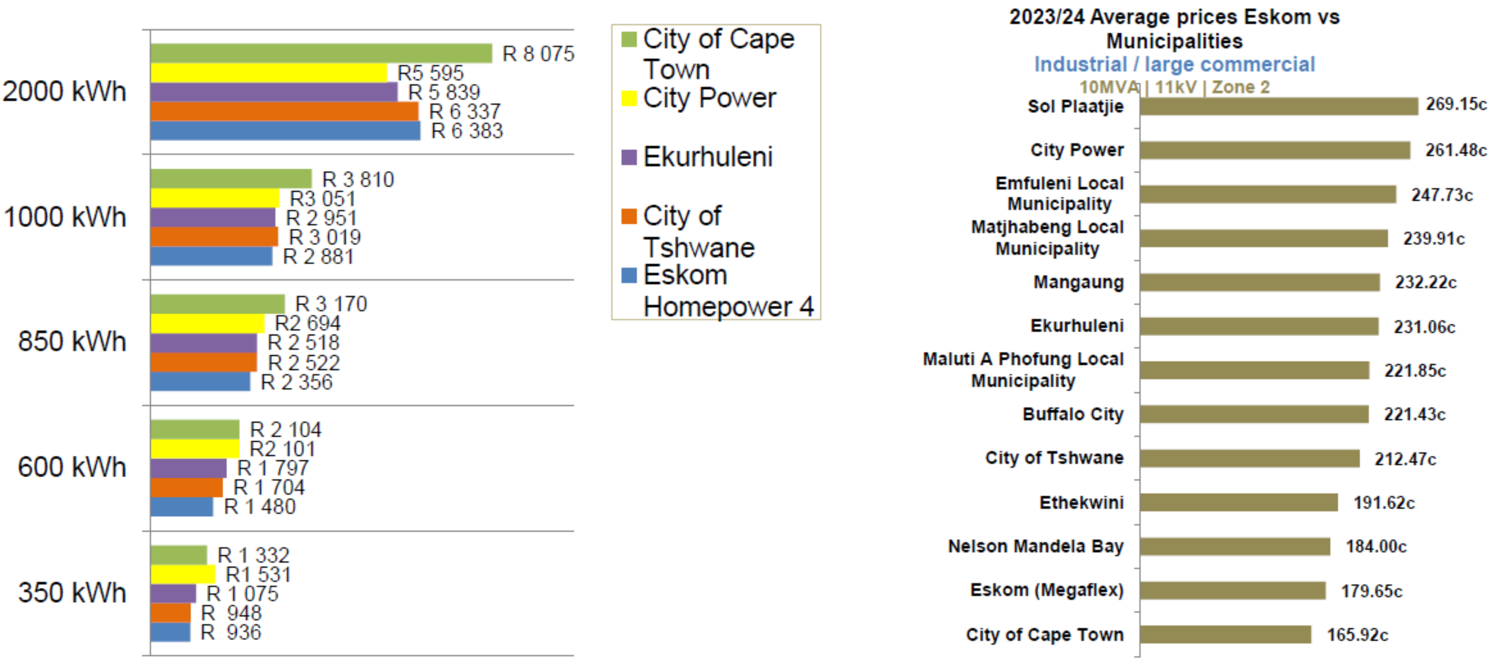
FIGURE 14: HOUSEHOLD ELECTRICITY PRICES - 2024



Eskom residential price comparisons are compared to various other countries above. This is a component of the Global Petrol Price study undertaken in 2024. Even with the 12.74% increase in FY2025, the prices are much lower than other countries. In certain instances, especially in certain countries in Africa, significant subsidies are provided to residential customers. This results in a slight distortion of the comparison.

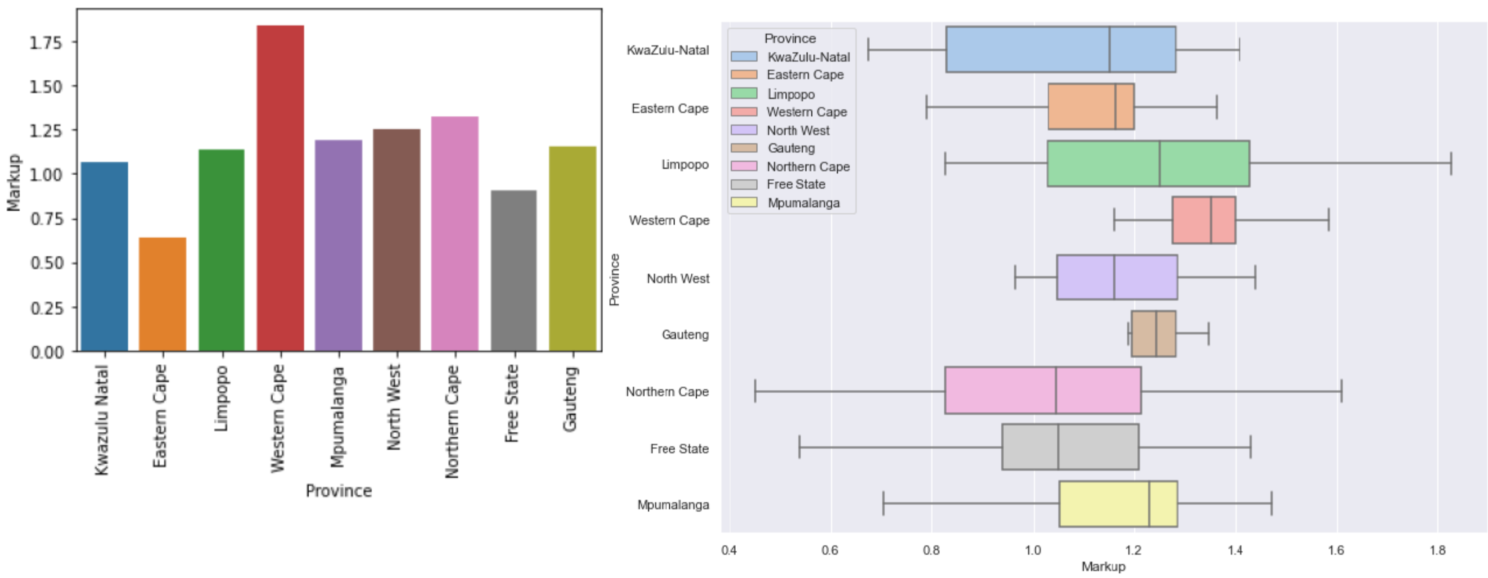
19.3 Eskom electricity price comparison to Municipal electricity prices

FIGURE 15: AVERAGE PRICES ESKOM VS MUNICIPALITIES FY2024



19.4 Municipal Comparison

FIGURE 16: MUNICIPAL PRICE COMPARISON



There is significant difference in pricing to end-customers between Eskom and Municipalities. Eskom prices are either the lowest or approaching the lowest in the country across the board. There is a wide disparity in the markups charged to municipal electricity customers, with markups ranging from 0.6 up to 2.0 times the purchase price from Eskom. This means there is very poor price equality across municipal electricity customers in South Africa with some customers paying significantly more than others for electricity.

20 Liquidation of RCA balances

The MYPD methodology requires a two-step process with regards to the RCA. These steps are:

- The **decision** on the **RCA balance** that is due to Eskom or the consumer, and
- The RCA balance decision will then be subject to an **implementation decision** (liquidation) guiding subsequent adjustments in tariffs.

This submission document, thus far, focused on the determination of the RCA balance. It is necessary for NERSA to make a decision on the implementation of the RCA balance by adjustment of tariffs in subsequent years.

20.1 Revenue and RCA balance decision yet to be recovered

NERSA and the High Court has made several revenue and RCA balance decisions that have not yet been liquidated. These decisions are listed below.

TABLE 85: REVENUE AND RCA BALANCES YET TO BE RECOVERED

Decision	Date of Decision	Balance Amount
MYPD 6 RAB re-determination	8 February 2026	R19 721m
RCA FY2015, 2016, 2017	9 May 2025	R17 358m
RCA FY2018	9 May 2025	R12 259m
RCA FY2019	9 May 2025	R 3 903m
RCA FY2020	9 May 2025	R2 371m
RCA FY2021	9 May 2025	R4 322m
RCA FY2021	23 February 2023	(R204m)
RCA FY2022	30 July 2024	R8 095m
RCA FY2023	27 March 2025	(R232m)
RCA FY2024	To be determined	Application – R15 847m
RCA FY2025	To be determined	Application – (R 8 858m)

The balance for the period FY2015 to FY2023 is R47 872m, yet to be liquidated. These are RCA decisions already determined. This balance is in reference to efficient revenue that has been recoverable for a period of three to eleven years. The decisions for FY2024 and FY2025 are yet to be made by NERSA. In addition, due to the correction of the MYPD 6 decision, a further R19 721m will be recovered after the efficient costs have been incurred. This delay is for a period of 1 to 3 years and by implication the phasing-in of this recovery has given consumers the opportunity to pay later for the service that they have already received.

The balance for the period FY2015 to FY2023 a total RCA balance yet to be liquidated is R47 872m. This balance is in reference to efficient revenue yet to be recovered for a period of three to eleven years. In addition, due to the correction of the MYPD 6 decision, a further

R19 721m is being recovered after the efficient costs have been incurred. This delay is for a period of 1 to 3 years. The implication is that due to the further phasing-in of the recovery, consumers have been given an opportunity to pay later for the service that they have already received.

20.2 Recovery of revenue and RCA balances in phased manner

It is proposed that the recovery of the RCA balances be phased in a manner that minimises the impact on customers. It should be noted that Eskom does not recover the time value of money as a result of the significant delay in the liquidation delays being made.

TABLE 86: ESKOM PROPOSAL FOR RECOVERY OF REVENUE AND RCA BALANCES

Decisions	FY2029	FY2030	FY2031	Total
MYPD6 RAB redetermination	R19 721m			R19 721m
RCA FY2021	(R204m)			(R204m)
RCA FY2023	(R232m)			(R232m)
RCA FY2025 (once determined)	(R8 858m)			(R8 858m)
RCA FY2015,2016, 2017 order	R12 573m	R4 785m		R17 358m
RCA FY2018 order		R12 259		R12 259m
RCA FY2019 order		R3 903m		R 3 903m
RCA FY2020 order		R2 371m		R2 371m
RCA FY2021 order			R4 322m	R4 322m
RCA FY2022			R8 095m	R8 095m
RCA FY2024 (once determined)			R15 847m	R15 847m
Total	**R23 000m**	**R23 318m**	**R28 264m**	

The table above provides a proposal for the recovery (liquidation) of revenue and RCA balances. The recovery is proposed to be implemented in phases to minimise the impact on consumers while contributing to the sustainability of Eskom. The recovery is maintained at approximately R23bn per annum for FY2029, FY2030 and FY2031. This is aligned to the recoveries, as determined by NERSA for FY2027 and FY2028. Keeping the recovery at the approximately the same level each year allows for no significant variance in price linked to these recoveries. The FY2024 and FY2025 RCA application have not yet been determined by NERSA. For the purposes of this proposal, it is assumed that the applied for RCA balances will be determined. It is acknowledged that this may not be the case. As decisions are made, NERSA can make adjustments in accordance.

21 Conclusion

This RCA application is for an amount of approximately R9bn in favour of the consumer. One of the key reasons for this benefit to the consumer, is a combination of the inability of Independent Power Producers to provide the energy as planned and Eskom being in a position to fill the gap of providing the energy. Eskom’s improved performance contributed to meeting the majority of the demand with only 13 days of load shedding. Additional operating costs were essential for the improvement of the overall Eskom operations. This investment in maintenance and employee benefit costs has resulted in reaching a more sustainable operational environment. Further growth and development would require continuation of this investment. The adjustments in other operating costs had to address the shortfall in the decision due to once-off adjustments. The variance in depreciation is due partly to the misalignment of NERSA’s RAB decision with its depreciation decision. It is proposed that the RCA balance decisions from 2015 to presently be liquidated in a phased manner to balance the impact on consumers and yet allow for Eskom’s sustainability.

>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>> **END >>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>**