Eskom

Eskom Summary

Eskom Multi-Year Price Determination (MYPD) 6 Revenue Application for FY2026 – FY2028

Submission to NERSA

August 2024

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Eskom MYPD6 Revenue Application Process

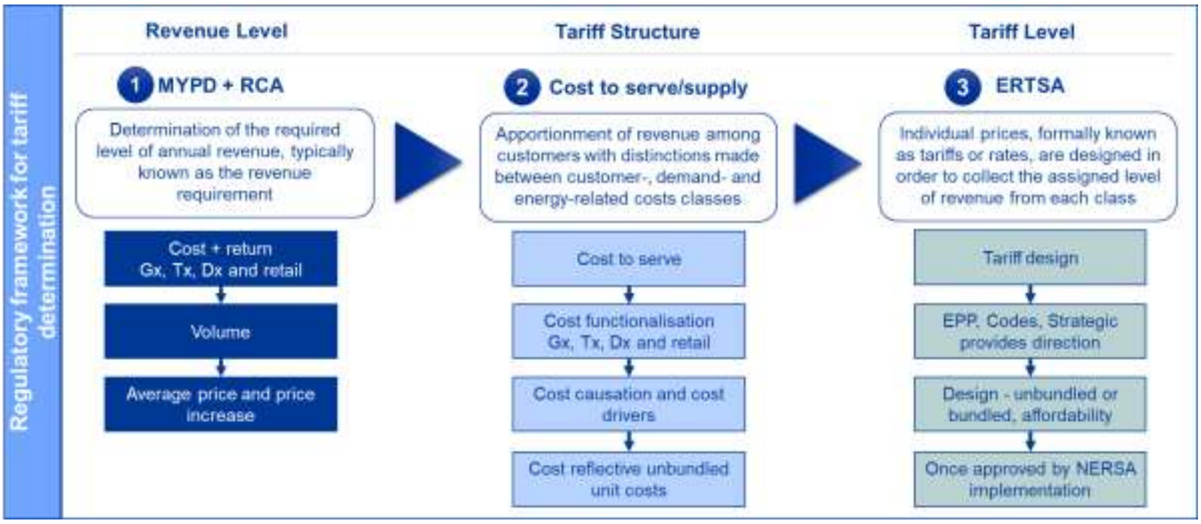
This Multi-Year Price Determination (MYPD) 6 revenue application is for the FY2026 to FY2028 period. This revenue application has been prepared in accordance with the MYPD methodology as published by NERSA during October 2016. The NERSA revenue and tariff decisions will be implemented from 1 April 2025 for non-municipal customers and from 1 July 2025 for municipal customers. The previous revenue application was for a three-year period and was implemented for the period from 1 April 2022 to 31 March 2025 for non-municipal customers; and 1 July 2022 to 30 June 2025 for municipal customers.

Eskom makes this revenue application, as it still migrates to a level that reflects the efficient cost of providing the electricity service. This has been a journey that Eskom and NERSA have been on for many years. Thus, the average price of electricity still does not cover the full efficient costs and cost of capital. The implication is that all electricity consumers have been receiving a subsidy and will continue to do so during this application period.

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 revenue application for FY2026 to FY2028. Once NERSA has determined the allowed revenue in terms of the MYPD methodology, the tariffs and price adjustments are determined by NERSA on an annual basis for the three-year period. These tariffs and price adjustments are determined in terms of the 2016 Eskom retail tariff and structural adjustment (ERTSA) methodology.

This revenue application recognises the RCA implementation decisions already made by NERSA, who have approved all RCA balance decisions up to FY2021. Tariffs have not yet been adjusted as a result of the FY2021 RCA balance decision. Eskom has submitted the FY2022 RCA application of R23 861m to NERSA on 26 April 2023 and the FY2023 RCA balance application of R9m to NERSA during January 2024. NERSA is yet to determine the RCA balances for both these applications.

FIGURE 1: OVERVIEW OF REVENUE AND TARIFF PROCESS



As illustrated above, the first step entails the determination of the revenue level. This is through a MYPD revenue application and the RCA determination. The next step is the apportionment of the revenue through the cost to serve methodology. The tariff level is determined through the ERTSA process. In the event that the any restructuring of the tariff occurs, this would prior to the determination of the tariff level.

Ringfenced revenue applications are made for Generation, Transmission and Distribution, as is accommodated by the MYPD methodology. It is recognised that the industry is undergoing a transformation. The roles being allocated to the National Transmission Company South Africa (NTCSA) are respected in this submission. To ensure compliance with the MYPD methodology as well accommodate the revised licensed roles, the appropriate links are drawn to allow for ease of reference. The Transmission roles are included in the NTCSA (Transmission) submission. Certain primary energy roles that were previously included in the Generation submission are now included in the NTCSA (Transmission) submission. This is still in compliance with the MYPD methodology.

Since 2021, NERSA has been consulting on the implementation of a new electricity price determination methodology. NERSA approved implementation of the Electricity Price Determination Methodology (EPDM) rules at its Energy Regulator meeting on 14 December 2023 and published the EPDM reasons for decision on 26 January 2024. It is understood that NERSA wishes to implement the rules with effect from the 2026 financial year; however, no formal communication on the implementation date has been received from NERSA. Subsequently, at its Energy Regulator meeting of 27 June 2024, NERSA rescinded its decision of 14 December 2023 on the EPDM rules. NERSA undertook to develop a plan on clarify the approach to processing and evaluating future revenue and tariff applications. Any approach will be in compliance with the Electricity Pricing Policy and the Electricity Regulation Act.

The High Court, in the order dated 5 July 2022, has confirmed that any revenue application needs to be made in accordance with a methodology that is in existence at the time. Any revised methodology, to be applicable, must have been completed having regard for any other regulatory requirements for the industry. In this instance, the order stipulated that the methodology that is in existence in the September (19 months prior to implementation) must be used for Eskom to make an application around June of the prior year (10 months prior to implementation). NERSA is required to make a decision around December (4 months prior to implementation). By implication, for implementation on 1 April 2025, a finalised methodology was required by September 2023 (at the latest). The only existing methodology for a revenue application in September 2023 was the 2016 MYPD methodology.

This application is being made when the industry is undergoing transition. The Electricity Regulation Act (ERA) amendment bill is awaiting the approval of the President of the country, to be finalised. The NTCSA, a wholly owned regulated subsidiary of Eskom has been operationalised on 1 July 2024. The NTCSA will de facto become the TSO when the ERA amendment is implemented. This process will be guided by transitional arrangements to be approved by NERSA as is reflected in the legislation.

Setting the context for the MYPD 6 revenue application

This MYPD 6 revenue application is being made at the end of the MYPD 5 period. The MYPD 5 decision was made through two separate decisions. The first MYPD 5 total allowable revenue decision of R250bn was made for FY 2023 in February 2022. This corresponded to an average price increase of 9.61% for standard tariff customers. A subsequent MYPD 5 total allowable revenue decision of R319bn was made for FY 2024 and R352bn for FY 2025 in January 2023. These corresponded to average price increases of 18.65% and 12.74% for standard tariff customers for FY 2024 and FY 2025 respectively. Both these decisions were in response to the revenue application made in June 2021. Updates were provided during the public hearings in both instances to allow NERSA to make decisions based on the latest information. The FY 2023 NERSA revenue decision was reviewed to ensure that the RAB values for the FY 2024 and FY 2025 were determined in accordance with the MYPD methodology. Court orders also guided the timing for both MYPD 5 determinations.

FY 2023 was a challenging year for Eskom from an operational point of view. Plant availability deteriorated to 56.03% (2022: 62.02%, MYPD 5 FY 2023 assumption of 62%), with unplanned load losses rising to 31.92% (2022: 25.35%) and planned maintenance at 10.39%

(2022: 10.23%). Load had to be curtailed by an estimated 13 476GWh (2022: 1 605GWh), with loadshedding on 280 days (2022: 65 days). Gas turbines produced 4 116GWh (2022: 2 725GWh) at a cost of R29.7 billion (2022: R14.7 billion) for Eskom and IPP OCGTs. Overall, IPP programmes delivered about 5 100GWh less than anticipated, contributing to the generation capacity shortfall. Transmission system minutes performance deteriorated to 4.71 minutes (2022: 2.88 minutes), with one major incident (2022: two). Distribution network performance remained resilient, with frequency and duration of supply interruptions well within target, although energy losses remain too high. Arrear municipal debt escalated to R58.5bn (2022: R44.8 bn), where NERSA did not allow for any arrear debts in its revenue determination. From a financial sustainability point of view, the net loss after tax worsened to R23.9 billion (2022: R11.9 billion).

As declared in Eskom's interim results as at September 2023, the following operational performance results were noted. EAF worsened further to 55.30% (Sep 2022: 58.66%), an increase in unplanned losses (UCLF) to 34.18% (September 2022: 30.86%). Average unplanned unavailability over the winter period (May to August 2023) was 16 513MW, resulting in loadshedding up to stage 6 on 183 days during the period (September 2022: 102 days), or 3 578 hours, which translates to an effective 149.1 days (September 2022: 1 653 hours equivalent to 68.9 days). Eskom and IPP OCGTs generated 2.9TWh during the period (September 2022: 2.1TWh), at load factors exceeding 20%. As at 30 September 2023, total municipal arrear debt stood at R70 bn (March 2023: R58.5 bn).

Eskom's operational performance has substantially improved in the first quarter of FY 2025. As of 24 July 2024, no load shedding has been experienced for the financial year. IPP OCGT load factor is 5.4%, Eskom OCGT load factor is 6.2% (Financial year to 22 July 2024). The year to date EAF as at June 2024 was recorded at 61.3%, with UCLF at 27.15% and PCLF at 10.96%. This supports the significant effort being put into the generation recovery plan implementation that is bearing fruit.

The Minister of Finance announced Government's debt relief plan for Eskom during the 2023 National Budget Speech in February 2023. The Eskom Debt Relief Act was subsequently promulgated on 7 July 2023 and will provide relief of debt servicing costs of R254 billion over the next three years. The first component will provide direct support of R184 billion to address our debt and interest payments as they fall due over the next three years. This support will initially take the form of a subordinated loan, which will be settled in ordinary shares on a quarterly basis once we have demonstrated, to National Treasury's satisfaction, that we have complied with the conditions attached to the support. The second component will see

Government take over R70 billion in Eskom debt commitments (both capital and interest) in 2026. The conditions announced during the 2023 National Budget Speech include that:

- Eskom's capital expenditure is restricted to transmission and distribution activities. The only capital expenditure that may be undertaken for generation relates to minimum emission standards, flue gas desulphurisation and required maintenance. No other greenfield generation projects will be allowed during the debt relief period
- Eskom may not use the proceeds from the sale of non-core assets for capital and operating needs. All proceeds from the sale of non-core assets, including Eskom Finance Company SOC Ltd and any property sales, will be used for the debt-relief arrangement
- No new borrowing will be allowed from 1 April 2023 until the end of the debt relief period, unless written permission is granted by the Minister of Finance
- Positive equity balances in Eskom's derivative contracts (swaps/hedges) may not be used to structure new debt or loan agreements without the approval of National Treasury. Any such balance may not be used as "margin financing" for another derivative contract or derivative overlays
- The debt relief can only be used to settle debt and interest payments
- Eskom may not implement remuneration adjustments that negatively affect its overall financial position and sustainability

National Treasury has subsequently clarified that the restriction on capital expenditure for generation will still allow for the completion of existing projects, such as Medupi and Kusile, the repowering and repurposing of Komati, battery energy storage, the life extension of Koeberg, as well as sourcing of nuclear fuel and investment in existing cost-plus coal mines. Greenfield generation projects may be undertaken, but only with the written approval of the Minister of Finance. The conditions to be attached to the Eskom Debt Relief Act, together with additional operational and financial conditions, have been finalised by National Treasury and DPE. The additional conditions aim to address key operational aspects including Generation plant performance, municipal debt recovery, skills development and further financial efficiencies.

The primary focus of Eskom's debt strategy going forward is to ensure strict adherence to the conditions attached to the debt relief package, to enable conversion of Government's subordinated loans to equity. This remains the only approach to deleveraging our balance sheet. Given the limitation on new borrowings, the debt relief package essentially requires

Eskom to ensure that the balance of debt servicing costs, as well as the cash flows required for the capital investment programme, are fully funded through cash generated from operations. The debt relief package is expected to improve financial sustainability by assisting us with our debt servicing challenges. Based on financial modelling, our gross debt securities and borrowings balance is expected to reduce by around 40% over the next five years, to below R270 billion.

As is evident, the purpose of this debt relief package is to delever the Eskom balance sheet. The package is applicable for a three-year period and comes to an end during this application period. The Minister of Finance has clarified that the migration of the South African price of electricity towards cost reflectivity is an essential element of the package. This package addresses the decades of shortfalls in revenue determinations and requires NERSA determinations that allows for a further narrowing of the gap between towards cost reflectivity. The debt support would come to naught if the gap to cost reflectivity is not narrowed.

It is against this backdrop that the MYPD 6 revenue application is being made. As is evident, a viable revenue determination contributes significantly to Eskom continuing to improve its performance. The stability provided by the debt relief package allows for meaningful investment decisions to be made. As that comes to an end during the MYPD 6 revenue application period, the migration towards cost reflectivity becomes an essential requirement for the sustainability of Eskom to provide an essential service.

Eskom MYPD 6 Revenue Application (FY2026 – FY2028) submission pack:

Eskom has included detailed submission documents to allow for further robust debate and understanding. These submission documents include:

1) **Eskom Revenue Application *Summary***, MYPD6 (FY2026 - FY2028)
2) **Eskom *Generation Licensee* Revenue Application**, MYPD6 (FY2026 - FY2028)
3) **Eskom NTCSA (*Transmission Licensee)* Revenue Application**, MYPD6 (FY2026 - FY2028)
4) **Eskom *Distribution Licensee* Revenue Application**, MYPD6 (FY2026 - FY2028)
5) **Abbreviations, Acronyms and Glossary**

Note on Casting of Tables

Certain tables may appear not to cast. However, it needs to be noted that in most cases the amounts reflected in the tables are rounded off to the nearest million rand. Thus, the totals are a true reflection of the underlying complete amounts.

1 Executive Summary

1.1 What revenues is Eskom applying for the MYPD 6 period?

Eskom is making a total revenue application of R446bn, R495bn and R537bn for FY2026, FY2027 and FY2028 respectively. This includes RCA and court outcome decisions. NERSA has already determined that in addition to the MYPD 6 revenue determination, previous court outcomes of R16bn will be recovered in FY2026 (R15bn of the recovery of ROA from MYPD 4 and R1bn RCA balance) and R14bn will be recovered in FY2027. This is related to the recovery of the R69bn ROA deducted during the MYPD 4 (FY 2020 to 2022) period. The Court allowed R10bn to be recovered in FY 2022. A subsequent court case required the recovery of R15bn each in FY 2024, FY 2025, FY 2026 and the remaining R14bn in FY 2027. NERSA could make further RCA determinations and liquidations that could impact this period. Further court outcomes could also be implemented during this period. The details of the revenue application in terms of the NERSA methodology are reflected in the table below.

TABLE 1: PROPOSED ALLOWABLE REVENUE APPLICATION FOR MYPD 6 PERIOD

Allowable Revenue (R'millions)	AR	Formula	Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Regulated Asset Base (RAB)	RAB		988 345	1 066 724	1 192 878	1 219 244	1 243 078	1 278 277
WACC %	ROA	X	1.58%	4.00%	5.00%	6.00%	7.47%	9.69%
Returns			15 616	42 669	59 644	73 155	92 908	123 916
Primary energy	PE	+	92 816	128 000	133 061	128 869	129 492	134 119
International purchases	PE	+	9 334	10 262	9 737	13 656	11 853	12 387
IPPs	PE	+	76 970	66 633	77 640	109 820	135 510	140 943
Environmental levy	L&T	+	6 503	6 539	6 279	5 337	4 781	4 767
Carbon tax	L&T	+	-	5 534	21 291	19 895	19 274	20 948
Arrear debt	E	+	-	8 914	9 917	10 752	12 037	13 310
Operating costs	E	+	61 442	93 315	93 834	97 864	100 152	105 100
Depreciation	D	+	73 376	66 931	69 952	77 431	79 685	85 961
MYPD6 Allowable Revenue			**336 057**	**428 798**	**481 355**	**536 778**	**585 691**	**641 450**
Add: Approved RCA/court order for liquidation	RCA		16 109	16 765	14 000	-	-	-
TOTAL MYPD6 Allowable Revenue	R'm		**352 166**	**445 563**	**495 355**	**536 778**	**585 691**	**641 450**

1.2 Tariff category increases to be experienced

The resultant standard tariff increases if NERSA approves the allowable revenue, as applied for, are shown in the table below. The deviations between the total standard tariff increases and the municipal adjustments is related to the impact of the difference in financial years (April vs July).

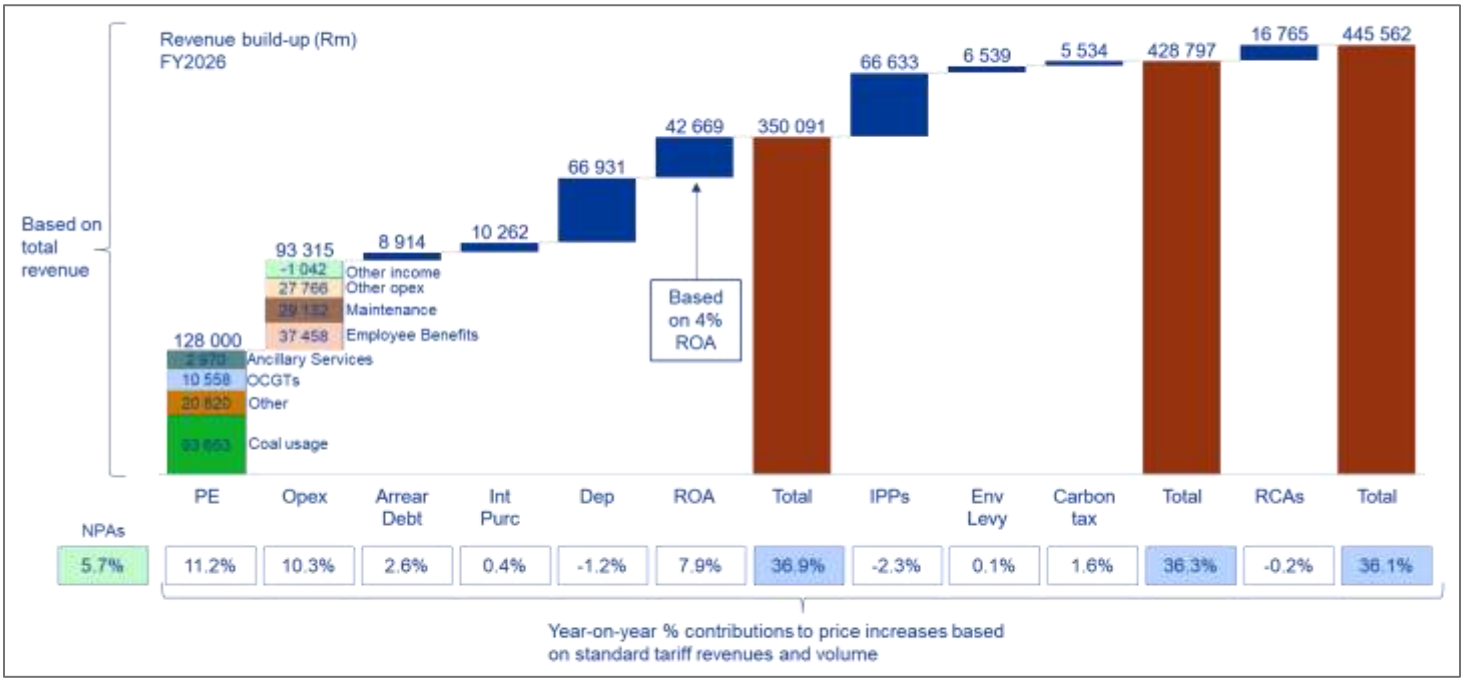
TABLE 2: RESULTANT TARIFF INCREASES FOR STANDARD TARIFF CUSTOMERS

Customer categories	Decision FY2025	Application FY2026	Application FY2027	Application FY2028
Total Standard tariff	**12.74%**	**36.15%**	**11.81%**	**9.10%**
Municipal - 1 July	**12.72%**	**43.55%**	**3.36%**	**11.07%**
Eskom Direct:				
Key Industrial and urban				
Megaflex; Miniflex; Nightsave Urban; WEPS; Megaflex Gen				
* Other tariff charges	12.74%	36.15%	11.81%	9.10%
* Affordability subsidy charge (where applicable)	25.64%	29.58%	25.42%	22.07%
Other Urban				
Businessrate; Public Lighting	12.74%	36.15%	11.81%	9.10%
Rural				
Ruraflex; Nightsave Rural; Ruraflex Gen	12.74%	36.15%	11.81%	9.10%
Homelight 20A				
Block 1 (>0-350kWh)	12.74%	36.15%	11.81%	9.10%
Block 2 (>350kWh)	12.74%	36.15%	11.81%	9.10%
Homelight 60A	12.74%	36.15%	11.81%	9.10%
Homepower	12.74%	36.15%	11.81%	9.10%

1.3 Indicative contributions to price increase in FY2026

To understand the 36% price increase in FY2026, it is necessary to understand the context even before the increased revenue from the latest projections is considered. In the FY2026, an additional 10 negotiated pricing agreements (NPAs) were included resulting in a 5.7% price increase for standard tariff customers in FY2026. These NPAs were approved by NERSA in accordance with the frameworks approved by the DMRE. The DMRE issued an Interim Long-term Framework for NPAs in 2020, in terms of the EPP, with its primary objective being to provide qualifying industries with a globally competitive electricity tariff to mitigate against the loss of baseload electricity sales and negative impact on other customers and the economy. NPAs are structured to ensure the global competitiveness of the sector from an electricity price perspective. The previous inadequate NERSA decisions, in FY2024, that do not consider the reality, results in an approximate 10% price increase in FY2026. The further adjustment for FY2025 is not included. This approximate 10% price increase is included in each of the relevant elements of the revenue application reflected below. It should be noted that once the corrections have been made in the initial year, subsequent year increases are more tempered. Primary energy costs are due partly to further dependence on coal-fired power stations to compensate for IPPs not materialising as envisaged. Operating costs require an adjustment to be set at a realistic level. In a bid to migrate towards cost reflectivity, the percentage return on assets (ROA) is being gradually increased. This is in line with a request by the Minister of Finance to allow for Eskom's migration towards financial sustainability and lessening the burden on the fiscus. The IPP costs include a ROA equivalent to their weighted average cost of capital (WACC). Introduction of the carbon tax liability from 1 January 2026 (last quarter of FY2026) results in a contribution to the price increase. There are further adjustments in FY2027 due to carbon tax liability for the entire financial year.

FIGURE 2: INDICATIVE CONTIBUTIONS TO PRICE INCREASES IN FY2026



Note: Primary Energy (PE) includes Ancillary Services; Int Purc - International Purchases; Dep – Depreciation; ROA – Return on Assets; IPPs – Independent Power Producers; Env Levy – Environmental Levy; RCAs – Regulatory Clearing Accounts

1.4 Indicative contributions to price increase in FY2027 and FY2028

In the two subsequent years, FY2027 and FY2028, as observed in the figures below, the price increase is impacted mainly by return on assets (in a bid to further migrate towards cost reflectivity), the delayed introduction of IPPs and introduction of carbon tax for the full year. The Eskom primary energy and operating costs do not significantly contribute to further increases.

FIGURE 3: INDICATIVE CONTIBUTIONS TO PRICE INCREASES IN FY2027

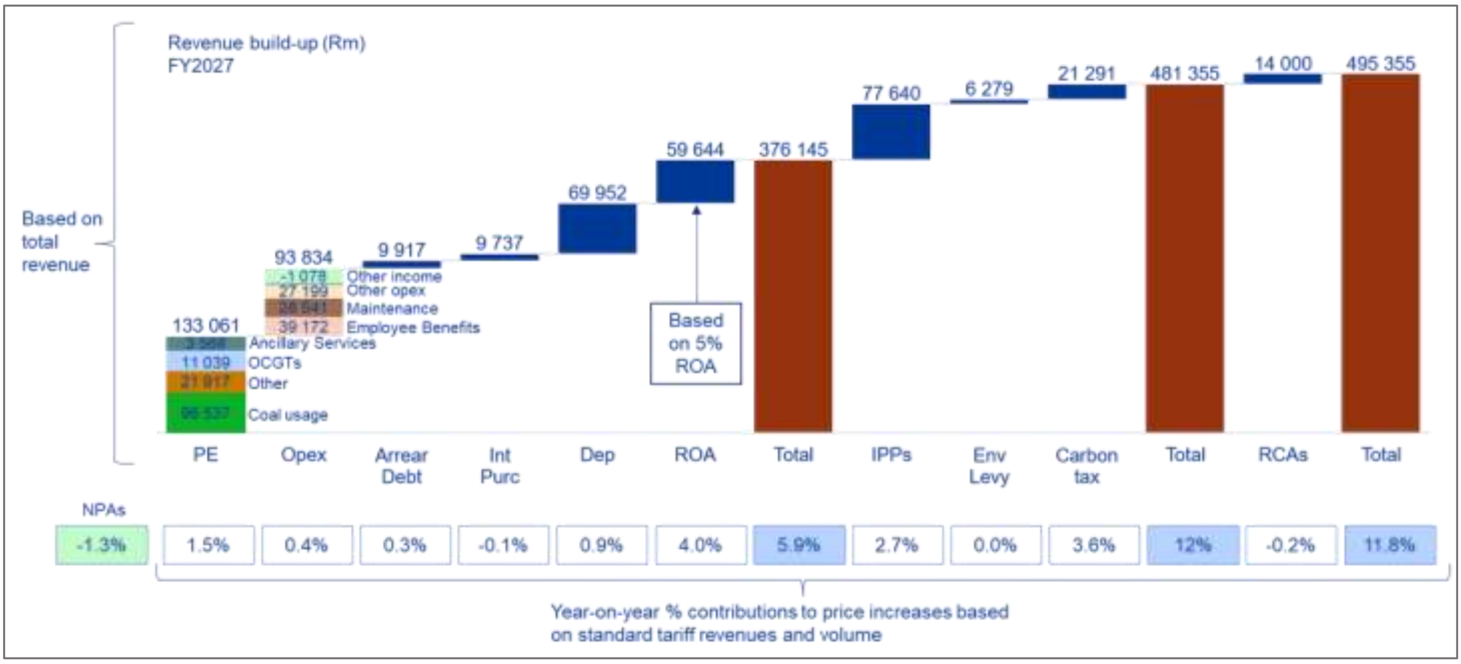
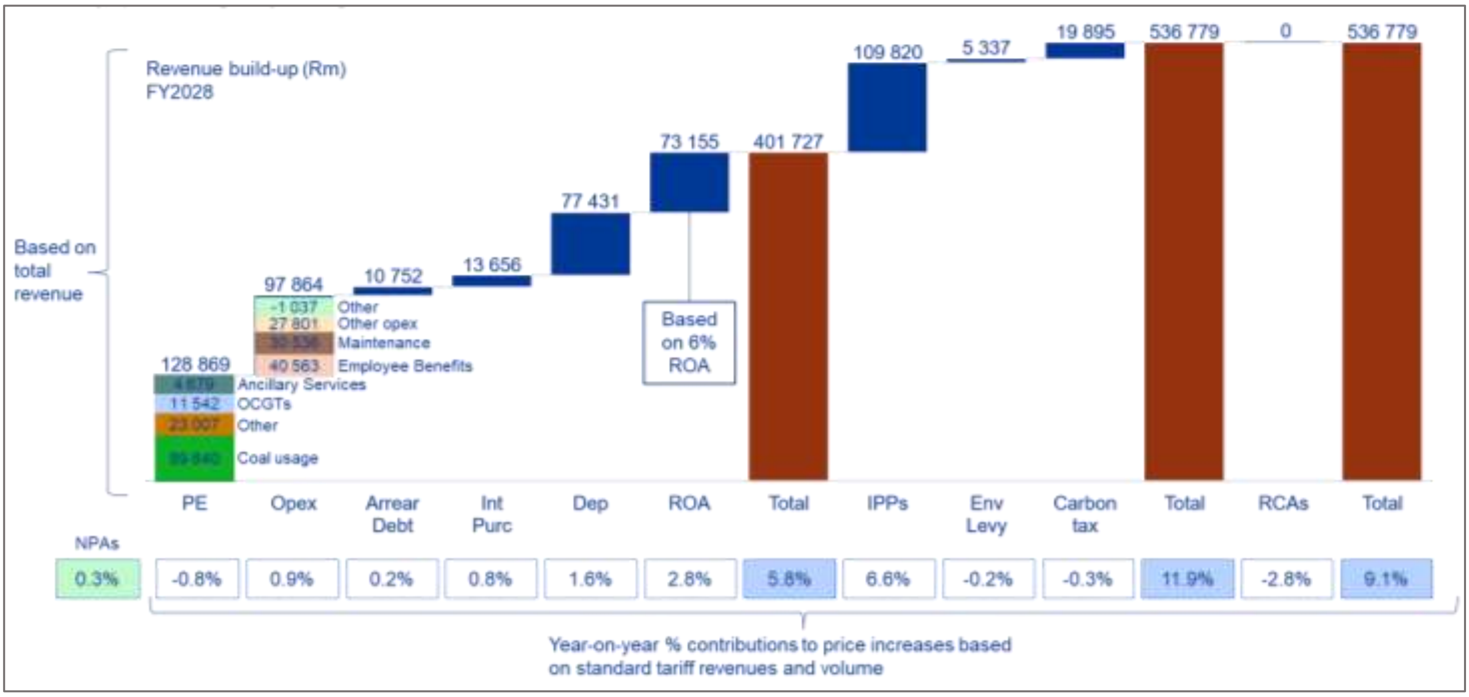


FIGURE 4: INDICATIVE CONTRIBUTIONS TO PRICE INCREASES IN FY2028



1.5 Eskom must meet the legislative and regulatory framework requirements

This MYPD 6 revenue application has been prepared in accordance with the MYPD methodology as published by NERSA during October 2016. The NERSA revenue and tariff decisions will be implemented from 1 April 2025 for non-municipal customers and from 1 July 2025 for municipal customers. The key outcome of the MYPD revenue application process is to determine the average price of electricity to the end consumer. This is the same situation as for the FY2025. When the ERA amendment is implemented, changes will be guided by NERSA.

This application is being made when the industry is undergoing transition. The ERA amendment bill is awaiting the approval of the President of the country to be finalised. The NTCSA, a wholly owned regulated subsidiary of Eskom has been operationalised on 1 July 2024. The NTCSA will de facto become the Transmission System Operator (TSO) when the ERA amendment is implemented.

Key legislative and regulatory requirements that guide the application include:

- Municipal Finance Management Act (MFMA)
- Electricity Regulation Act (ERA)
- Government Support Framework Agreement (GSFA)
- Frameworks - short term and interim long term negotiated pricing agreements
- Other legislative and regulatory requirements and precedents.

1.6 Eskom generators need to fill the gap created by the IRP not being implemented

In the period 2019 to 2023 – over 8 000MW of capacity was not made available to the system as envisaged in the implementation of the Integrated Resource Plan (IRP) 2019. In addition, it is unlikely that further capacity that was expected to be made available timeously, will occur. This includes the dispatchable 1 500MW of coal and 3 000MW of gas capacity. Furthermore, sufficient attempt has not been made for any alternate dispatchable new build capacity. The practical outcome of the lack of new build delivery exerts further pressure on Eskom generators to fill the gap. In addition, the grid constraints contributed to the inability of IPPs to connect to the grid and thus impacted their availability.

1.7 External reviews recommendations align with Eskom recovery plans

A comparative analysis of various external reports on Eskom Generation has identified three categories of focus, namely, People, Leadership and Human performance; Plant Performance; and Processes, Governance and Finance. Multiple actions and programmes are already in place to address the shortcomings highlighted in the reports. Eskom Generation is managing the recommendations and actions and will continue to drive their implementation. Central organisational actions are being incorporated into the Generation recovery plans. Since the Eskom Board approval of the Generation Recovery plan in March

2023, Generation is confident that significant progress is being made in addressing systemic organisational challenges.

1.8 Addressing crime, fraud and corruption

Eskom has intensified its focus on response to the effects and aftermath of state capture as well as criminality, in the form of fraud, corruption, theft and sabotage. Over time, these issues have eroded Eskom's operational and financial sustainability as well as its reputation and relationships with key stakeholders. The Board acknowledges that addressing these matters will be a lengthy process and recognises that more internal work is required to eradicate the criminality that affects the organisation. Eskom will continue to comply with the NERSA requirement to ensure any recovery will be included in subsequent RCA applications.

1.9 Addressing Municipal debt

Eskom's gross arrear debt is currently R74bn as at FY2024. The average payment level for all customers, over the past 12 months was 95% with the Municipal segment at 89%. Municipal debt and revenue collection remain a key challenge. Since 2015 various medium and long-term interventions took place to reduce and contain the Municipal debt. Through this period there has been numerous litigation matters. These have culminated in the National Treasury Debt Relief Programme, aimed at assisting Municipalities to deal with the historical overdue debt and focus on the payment of current debt. It is submitted that this approach is not achieving the desired result. The debt burden continues to increase. Further, stricter interventions are required where the ability to pay the Eskom debt is prioritised. Where it is not possible, the underlying factors must be addressed. These underlying factors at local Government level need to be addressed holistically. It is now time for bolder and more innovative solutions that allows municipalities to move to the right path.

1.10 Eskom requires reasonable tariff increases to address financial sustainability and liquidity challenges

Liquidity and solvency risks pose an inordinate threat to Eskom's ability to continue as a going concern. To improve liquidity, we have restricted organisational cash requirements through targeted savings. There is a heavy reliance on Government support to maintain a positive cash balance at year end, with increases in equity. Due to high debt servicing obligations, maintaining the liquidity buffer at acceptable levels continues to be a challenge.

The two key sources of funding of Eskom presently, are equity and tariffs. It goes without saying that Eskom must continue to find further efficiencies in the way that the business is run. The Government has provided support for a limited time. Although Government's debt support assists with liquidity requirements, it does not adequately enhance our long-term financial sustainability. The Government, through the Minister of Finance, has stressed that Eskom needs to migrate towards cost reflective tariffs that will make it sustainable. The Government is not in a position to continue providing further support. This requirement has necessitated Eskom applying for increasing levels of ROA over the application period. It needs to be noted that IPPs are already including a ROA that is equal to their WACC. The only way to achieve financial sustainability is to improve operating cash flows that results in positive free cash flows, with a strong focus on moving to a prudent, cost-reflective tariff.

We acknowledge the importance of cost savings to improve liquidity, with a focused cost curtailment programme over the next three years. Nonetheless, cost savings alone will not be sufficient to improve our financial health. For Eskom and the electricity supply industry to continue to operate and maintain its assets in a reliable state, the price of electricity must migrate towards cost-reflectivity to ensure Eskom's long-term financial sustainability. Without a cost-reflective tariff path, we will remain reliant on Government support, which implies that the taxpayer will continue to foot the bill for the revenue shortfall, which is contrary to the "user pay" principle.

1.11 NERSA to restructure tariffs that are reflective of cost

This revenue application does not deal with any potential Eskom tariff structural changes. A separate approval process for restructuring of tariffs will be made to NERSA for implementation from FY2026. In pursuit of the country's tariff objectives, in line with the Electricity Pricing Policy (EPP), a Retail Tariff plan (RTP) was submitted to NERSA in 2020 and again in 2022. Both were not approved by NERSA in the main. Eskom will again submit an updated RTP in 2024 for approval. The significance of the proposed tariff structural changes allows for cost representative pricing that enables sustainability for all electricity supply industry participants. The key reasons for the proposed changes include the need to align tariff rates with divisional costs, reflect the evolving energy industry, and ensure revenue recovery. The current tariff rates no longer accurately reflect the different services provided by Eskom. Furthermore, the evolving nature of the energy industry necessitates the modernisation of tariff structures. Changes such as the increasing prevalence of customer-owned generation and the evolving patterns of grid usage require tariff structures that can adapt to these changes. Additionally, there is a need to ensure that wholesale purchase costs are accurately reflected in retail tariffs. This alignment is crucial to avoid a disconnect between the tariff structures, ensuring that the costs incurred in purchasing energy at the wholesale level are appropriately passed on to customers at the retail level. The evolution of tariff structures is also essential to protect the interests of all customers.

1.12 Economic impacts are best managed by continuing to migrate towards cost reflective prices of electricity

It may be tempting to conclude that by limiting electricity tariff increases and requiring that Eskom and/or government borrow the revenue shortfall, it is possible to minimise the negative impacts of rising electricity prices on gross domestic product (GDP) and employment growth in the short-term. It is ill-advised for NERSA to continue to limit Eskom's tariff increases below cost-reflective levels. Tariff increases should at least be sufficient to transition Eskom towards a more cost-reflective electricity tariff (prudently and efficiently incurred) over the next few years. The protection of vulnerable sectors, including poor households and certain industrial sectors are being addressed by Government-led interventions. Eskom is dependent on NERSA making revenue and tariff decisions in accordance with its mandate, policy, relevant legislation and in compliance with related Court orders.

2 Basis of Application

2.1 Legislative and regulatory framework

The key outcome of the MYPD revenue application process is to determine the average price of electricity to the end consumer. This is the same situation as for the FY2025. When the ERA amendment is implemented, changes will be guided by NERSA as articulated in the legislation.

When Eskom makes its revenue applications, it is required to do so in terms of the relevant legislation and regulations. This ensures that only efficient and prudent costs are recovered from consumers. The key requirement for Eskom and NERSA is to ensure that we comply with the ERA and the MYPD methodology when Eskom makes its application and when NERSA makes its determination. NERSA requires Eskom to meet the requirements of the MYPD methodology, which in essence is the translation of the requirements of the ERA, in this instance. The Supreme Court of Appeal has confirmed that the MYPD methodology is a policy requirement that needs to be adhered to.

The High Court, in the order dated 5 July 2022, has confirmed that any revenue application needs to be made in accordance with a methodology that is in existence at the time. Any revised methodology, to be applicable, must have been completed having regard for any other requirements for the industry. In this instance, the order stipulated that the methodology that is in existence in the September (19 months prior to implementation) must be used for Eskom to make an application around June of the prior year (10 months prior to implementation). NERSA is required to make a decision around December (4 months prior to implementation). By implication, for implementation on 1 April 2025, a finalised methodology was required by September 2023 (at the latest). The only existing methodology for a revenue application during September 2023 was the MYPD methodology, as published during 2016.

This application is being made when the industry is undergoing transition. The ERA amendment bill is awaiting the approval of the President of the country, to be finalised. The NTCSA, a wholly owned regulated subsidiary of Eskom has been operationalised on 1 July 2024. The NTCSA will de facto become the TSO when the ERA amendment is implemented. This process will be guided by transitional arrangements to be approved by NERSA as is reflected in the legislation.

When a revenue application is made by Eskom, before considering the application, NERSA ensures that the requirements of the MYPD methodology and guideline document, Minimum Information Requirements for Tariff Applications (MIRTA), are complied with. NERSA is required to undertake this confirmation within two weeks of the application being submitted. If compliance is not achieved, then Eskom must provide further information to reach compliance. The principles outlined in the judgments of recent reviews of NERSA revenue and RCA decisions are adhered to, as applicable, in this revenue application.

In terms of the GSFA, Eskom is required to ensure that collective **approval** is received from the Department of Mineral Resources and Energy (DMRE), Department of Public Enterprises (DPE) and National Treasury for Section 34 (of the ERA) IPP purchases and associated costs.

In terms of the MFMA, (Section 42), Eskom is required to consult with National Treasury and organised local Government (South African Local Government Association) prior to making a revenue application to NERSA. In addition, Eskom's application needs to be made timeously to allow NERSA to make revenue and tariff decisions to facilitate Municipal budgeting processes. The optimal timing is the December prior to the Municipal financial year, which is from 1 July to 30 June the next year. Thus, for MYPD 6, Eskom understands that NERSA is required to make a decision by December 2024.

The adherence to the various related legislative, regulatory and licence requirements form the basis of the MYPD application. Eskom has however allowed for the smoothing of the tariff increases as well as a migration towards cost reflectivity. The following are certain key requirements applicable to the determination of Eskom's allowed revenue and resulting tariff adjustments.

2.1.1 Municipal Finance Management Act (Act 56 OF 2003)

Eskom is required to take into account comments from the National Treasury and organised local government on the draft revenue application. The revenue application should include a motivation for adjustment of tariffs; consideration of impact on inflation targets and other macroeconomic policy objectives; as well as Eskom's efficiency improvements**.** There is a need to timeously table approved adjusted tariffs in Parliament for implementation for Municipal customers.

2.1.2 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
- Avoidance of undue discrimination between customer categories
- Permitting the cross subsidy of tariffs to certain classes of customers by the Energy Regulator
- Approval of tariffs by the Energy Regulator

2.1.3 Electricity Pricing Policy (EPP)

EPP gives broad guidelines to the Energy Regulator in approving prices and tariffs for the electricity supply industry.

2.1.4 Government Support Framework Agreement (GSFA)

The GSFA with regards to the DMRE procured IPPs, under section 34 of the ERA, was signed by Government (represented by the DMRE, DPE and Finance Ministers) and Eskom in 2012. In accordance with section 3.1.4(e) of the GSFA, Eskom is required to seek approval from the DMRE, DPE and National Treasury on the proposed IPP purchase costs and payment obligations to be included in any revenue application.

2.2 NERSA Guidelines for Prudency assessment

NERSA issued guidelines for prudency assessment during August 2018. Eskom will base this revenue application on the principles of this guideline. Certain aspects that are pertinent to this application are included here.

S2.4 *The guidelines will formalise the use of a uniform approach and assists licensees in knowing (in advance) the basis on which the assessment was conducted. They will also inform the licensees of the specific area or information that the Energy Regulator will focus on when assessing prudency matters.*

S2.5 *The existence of the guidelines is expected to improve regulatory certainty in the long term and provide a transparent framework by ascertaining whether costs were or will be incurred prudently.*

S5.2.1.4 *The MYPD Methodology requires the Energy Regulator to review the efficiency of all contracts, such as those between Eskom and IPPs, before the conclusion of the contracts, to ensure prudency. It also requires that there be a fair risk allocation between the IPP and Eskom, as the buyer.*

S6.1.1.2 *Whether a cost is prudently incurred depends on how the decision was made, not only the outcome of the decision*

S6.1.1.3 *In assessing prudency, the following will be considered: b. Expenditure that meets a standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by licensee at the time the decision had to me made*

S6.1.2.3 *Efficient costs can also be those that can make the licensee more efficient over the long term and improve the experience of the customers' experience of the licensee's service. NERSA however recognises that that there are instances and circumstances where these may not be the least cost option.*

S8.3 *In assessing prudency, it is necessary to make a distinction between forecast and committed costs*

S8.3.b *Committed costs are costs that the utility has already spent or has entered into a binding commitment to pay or is subject to other legal obligations that leave it with no discretion as to whether to make the payment in future. The disallowance of committed costs is particularly problematic for a regulated entity because the regulated utility and its shareholders will have no choice but to bear the burden of these costs themselves.*

S8.6 *In using the Guidelines for prudency assessment, it should be emphasized that hindsight provides perfect insight, which is not available or could not reasonably have been known to those making the decisions. Therefore it cannot be used to assess the decisions made. The assessment of decisions made must be done by first establishing what was known at the time, as well as what influences were at play at the time the decision was made.*

2.3 Guideline on Minimum Information Requirements for Tariff Applications (MIRTA)

Eskom accepts that MIRTA is not prescriptive. It is a guideline providing direction to the licensee in compiling a revenue application. Eskom will endeavour to address the requirements as far as possible.

2.4 Eskom Retail Tariff and Structural Adjustment (ERTSA) Methodology

The 2016 ERTSA methodology governs the tariff increases to the Standard tariffs. The ERTSA is applicable to Eskom's Standard tariffs for local authorities (Municipal) and non-local authorities (non-municipal). Eskom is required to submit an ERTSA application prior to the start of each financial year. The revenue decision applicable for the particular year as well as any RCA liquidation decisions will need to be considered when the ERTSA application is made. The ERTSA application consists of an application for the rate of adjustment to Standard tariffs and the proposed Schedule of standard tariffs for each financial year.

2.5 Frameworks - short term and interim long term negotiated pricing agreements

The DMRE has amended the short term negotiated pricing agreements (NPA) framework and developed an interim long term NPA framework in accordance with the requirements of the EPP. The Short-term NPAs have been specifically structured to provide opportunities to sustain existing businesses that are at risk of failure and permit others that have closed production capacity in recent years, owing to their inability to compete in their markets, to restart. The rationale for the interim long-term framework is to protect vulnerable sectors, improve relative sector competitiveness and attract investment in the long-term. These two frameworks will allow for the relevant vulnerable sectors, which are impacted by the price of electricity and meet the required criteria, to be supported to allow for further contribution to economic activity of the country.

2.6 Various other legislative and license requirements

As is the case for any entity, Eskom is required to comply with a myriad of legislative requirements. This is also reflected in the Eskom licenses, granted by NERSA. Key amongst these legislative requirements is the Public Finance Management Act, Company's Act, various procurement related legislation, health, safety and environmental legislation, nuclear legislation as well as labour related legislation.

The NERSA regulatory principles that are depended upon include transparency, neutrality, integrity, consistency and predictability.

2.7 Outcomes of various High Court applications

The outcomes of the various High Court decisions are respected in this MYPD 6 application.

2.8 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 RCA process. **The focus of this application is the MYPD revenue application for the FY2026 to FY2028.** It is clarified that this revenue application **does not include any further RCA adjustments**.

NERSA and Eskom are still in the process of aiming to reach a level that corresponds to an average price of electricity that is reflective of the **efficient cost** of producing the electricity and the associated service. It needs to be clarified that NERSA will undertake analysis of

Eskom's application, make benchmark comparisons and apply prudency criteria to determine the **efficient costs** of providing the service. Thus, any form of inefficiency, as determined by NERSA, is not included in the price of electricity. In essence, NERSA determines the price level that reflects the efficient cost of electricity. The MYPD methodology allows only for efficient and prudent costs to be recovered through its application.

2.9 Application does not include further RCA adjustments

It is clarified that Eskom has not applied for any further RCA adjustments in this revenue application. Only the RCA implementation decisions that have already been made are considered when the average price increase is determined. Any further RCA liquidation decision made by NERSA could be included in the final tariff adjustment decision.

2.10 Establishment of National Transmission Company South Africa (NTCSA)

The NTCSA has been established in terms of the Roadmap for Eskom in a reformed Electricity Supply Industry (2019). (ISBN: 978-0-621-47981-2). This is a document published by the DPE, it is not legislation. It is envisaged that when the ERA amendment is promulgated, the NTCSA will become the TSO. The NTCSA has been awarded three licenses by NERSA. These are a facilities licence, a trading licence and an import/export licence. The NTCSA has been operationalised on 1 July 2024. To respect the defined roles of the entity, these are included in the NTCSA (Transmission) submission.

2.11 Electricity Regulation Act Amendment

The amendment of the ERA has been finalised through the Parliamentary process. It is presently awaiting signature by the President of South Africa. The objective of the ERA amendment includes the provision for the establishment of the TSO and to provide for a competitive multi market structure for the electricity industry. It is envisaged that once this amendment is promulgated, NERSA will be empowered to implement transitional arrangements that will guide the industry.

3 Allowable Revenue

3.1 Allowed Revenue formula

Eskom applies only for efficient and prudent costs based on forecasts for the MYPD 6 period. The forecasts are based on motivations provided for each of the changes in the particular cost element of the regulatory formula. The details in the environment related to each efficient cost is also provided, to the extent possible. The MYPD methodology, with regards to the revenue application is based on a particular formula. The regulatory framework in which Eskom's regulated revenue and tariffs are set provides that the licensee is to recover its prudent costs of service. This 'cost of service' approach is a common feature of regulatory pricing frameworks and is employed by NERSA in other sectors; by other economic regulators within South Africa; and by utility regulators globally. It is submitted that whatever the structure of the industry, a need for the allowable revenue to correspond to the efficient and prudent cost of providing the service will be required.

Eskom's revenue requirement application for FY2026 to FY2028 is based on the allowed revenue formula as reflected in the MYPD methodology:

$$AR=(RAB\times WACC)+E+PE+D+R\&D+IDM\pm SQI+L\&T\pm RCA$$

Where:

AR	=	Allowable Revenue
RAB	=	Regulatory Asset Base
$WACC$	=	Weighted Average Cost of Capital
E	=	Expenses (operating and maintenance costs)
PE	=	Primary Energy costs (inclusive of non-Eskom generation)
D	=	Depreciation
$R\&D$	=	Costs related to research and development programmes/projects
IDM	=	Integrated Demand Management costs
SQI	=	Service Quality Incentives related costs
$L\&T$	=	Government imposed levies or taxes (not direct income taxes)
RCA	=	The balance in the Regulatory Clearing Account (risk management devices of the MYPD)

3.2 Allowed revenue if MYPD Methodology is applied

In this application, Eskom is allowing the ROA component to be migrated towards during the entire period. Eskom is not at all considering the scenario where a full ROA is being applied for. It is felt that the resultant increases would be untenable for the consumer. Eskom has decided to only consider options that continue to phase-in the ROA. This, in essence, further contributes to the delay of the implementation of the EPP with regards to reaching cost reflectivity by 2013, shifting the goal posts further down the road. Eskom’s continued migration towards cost reflectivity results in a shortfall of revenue. This efficient revenue will need to be sourced from elsewhere, since it is not being included in the price of electricity. This results in Eskom continuing to burden the fiscus.

3.3 Proposed MYPD 6 Allowed revenue application

Eskom is making a total revenue application of R446bn, R495bn and R537bn for the FY2026, FY2027 and FY2028 respectively, including the RCAs and court order. NERSA has already determined that in addition to the MYPD 6 revenue determination, previous court decisions and RCA determinations of R16,8bn will be recovered in FY2026 and R14bn will be recovered in FY2027. In the event that NERSA makes further liquidation decisions related to court outcomes or RCA decisions, further adjustments could occur. Eskom, in this revenue application, has applied the NERSA MYPD methodology, with a smooth phasing-in of ROA. Thus, the MYPD methodology is not being applied in its fullest form. The phased implementation of the ROA together with depreciation allows to partly cover expansion and repairs that are urgently required. The remainder of the cost elements of the revenue application are in accordance with the MYPD methodology. The methodology requires the projections to be based on most recent prudently and efficiently incurred actual costs. Eskom makes its revenue application in accordance with this requirement. The application is based on the latest actuals (FY2023) with projections for FY2024 and FY2025. In many instances, a significant increase is required for the first application year when comparing to a previous decision. This is due to NERSA not sufficiently considering these projections when the previous decision was made. The details are reflected in the summary table below. Further details on each of the elements of the application for FY2026 to FY2028 are provided in subsequent sections of this application.

TABLE 3: PROPOSED ALLOWABLE REVENUE APPLICATION

Allowable Revenue (R'millions)	AR	Formula	Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Regulated Asset Base (RAB)	RAB		988 345	1 066 724	1 192 878	1 219 244	1 243 078	1 278 277
WACC %	ROA	X	1.58%	4.00%	5.00%	6.00%	7.47%	9.69%
Returns			15 616	42 669	59 644	73 155	92 908	123 916
Primary energy	PE	+	92 816	128 000	133 061	128 869	129 492	134 119
International purchases	PE	+	9 334	10 262	9 737	13 656	11 853	12 387
IPPs	PE	+	76 970	66 633	77 640	109 820	135 510	140 943
Environmental levy	L&T	+	6 503	6 539	6 279	5 337	4 781	4 767
Carbon tax	L&T	+	-	5 534	21 291	19 895	19 274	20 948
Arrear debt	E	+	-	8 914	9 917	10 752	12 037	13 310
Operating costs	E	+	61 442	93 315	93 834	97 864	100 152	105 100
Depreciation	D	+	73 376	66 931	69 952	77 431	79 685	85 961
MYPD6 Allowable Revenue			**336 057**	**428 798**	**481 355**	**536 778**	**585 691**	**641 450**
Add: Approved RCA/court order for liquidation	RCA		16 109	16 765	14 000	-	-	-
TOTAL MYPD6 Allowable Revenue	R'm		**352 166**	**445 563**	**495 355**	**536 778**	**585 691**	**641 450**

3.4 Impact of NERSA's previous revenue decision

The increase in revenue requirement in FY2026 is compared to the previous NERSA revenue decision made. Inadequate decisions made in the past have a severe impact on the application years. Due to having to correct for the past decision, it has been found that the first year of the three-year cycle needs to allow for a correction to the reality in terms of the MYPD methodology. It is quite clear that NERSA does not adequately consider the latest actuals, followed by the subsequent projections, when it analyses the revenue application being made. It is acknowledged that these actuals and projections need to be analysed in terms of NERSA methodologies and frameworks, especially the prudency framework to provide a sense of what has transpired and the best projections of the immediate future. It is unfortunate that NERSA continues to make revenue decisions based on its previous decisions – and does not analyse the latest reality. In addition, the adjustments made by NERSA in its RCA decisions are not at all considered when it makes a subsequent revenue decision.

As an example, for employee benefit costs, Section 10.4.9 of the MYPD methodology refers to "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" – thus, Eskom provides a motivation based on the latest actuals. However, NERSA bases its decision on a previous decision it made – and allows an increase for employee benefit costs on a previous decision. This ends up in a continuous incorrect spiral – since the basis is incorrect.

NERSA also has a guideline for prudency document and the objective is *inter alia:*

“2.4 The Guideline formalises the use of a uniform approach and assist licensees in knowing (in advance) the basis on which the assessment is to be conducted. They will also inform the licensees of the specific areas or information that the Energy Regulator will focus on when assessing prudency matters.

“2.5 The existence of the Guideline is to improve regulatory certainty in the long term and provide transparent framework by ascertaining whether costs were or will be incurred prudently.”

By the intention set in the Guideline which follows from the methodology it is clear that costs need to be assessed for prudency. They need to be evaluated on the merits by the Energy Regulator. A simple application of an inflation increase does not indicate that the costs were evaluated for prudency, efficiency and reasonableness. Prudency is linked to the MYPD Methodology as follows:

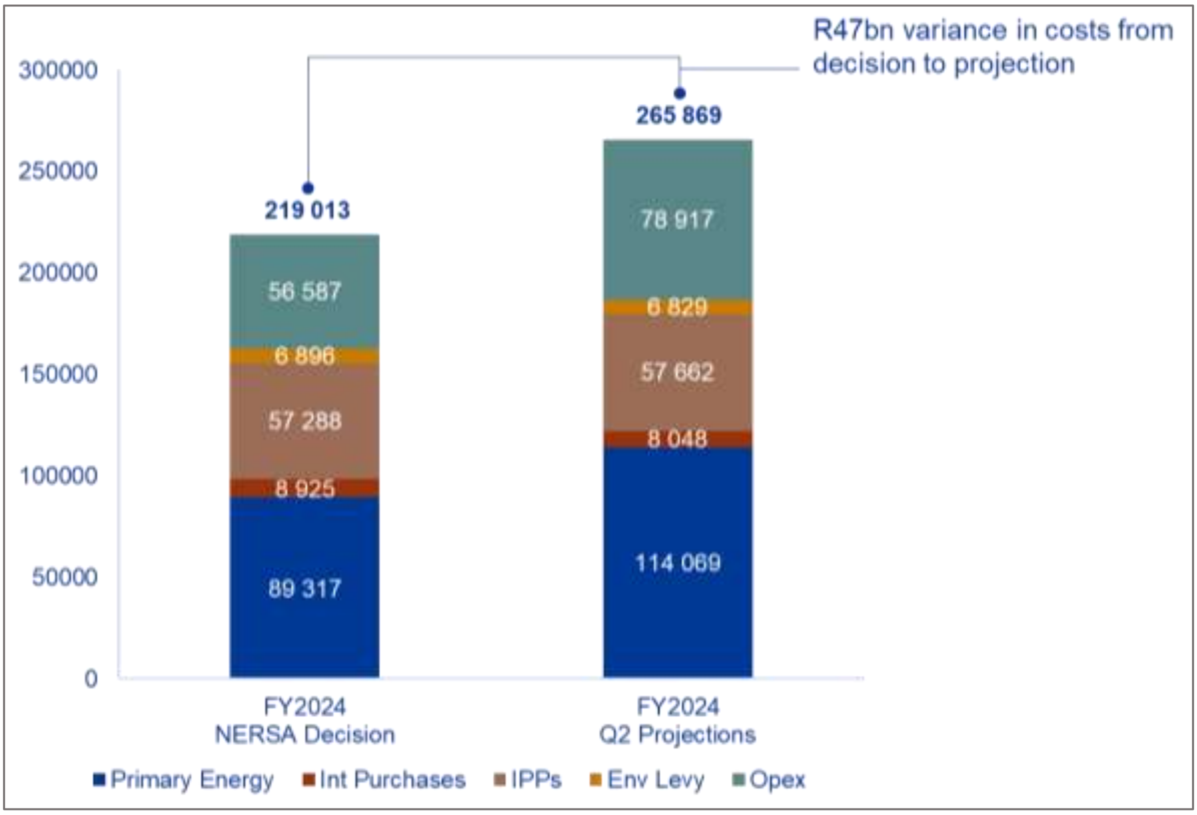
“5.2.1.5 Although prudency is not a term used in the ERA, prudency is directly linked to efficiency, and it is international best practice for regulators to assess the prudency of expenditure. Efficient Licensees will make prudent decisions and prudent decisions will make a licensee efficient, which is why the assessment of prudency is included in the MYPD Methodology. The MYPD Methodology requires that the licensee exercise prudence in all its regulated activities. This is in accordance with the requirements of Policy Position 1 of the EPP.”

It needs to be noted that the majority of Eskom’s costs are based on underlying contracts. These contacting processes are governed by a myriad of policy and legislative requirements. These include ensuring compliance to the Public Finance Management Act (PFMA), the various procurement legislations and policy as well as meeting National Treasury requirements. This demonstrates the rigour and thoroughness that Eskom has to adhere to before finalising any contract. In addition, compliance is monitored by many authorities including the National Treasury. NERSA would need to take this into consideration when determining the prudency of Eskom’s costs.

The following NERSA statements in previous decisions illustrate that NERSA is not applying its methodologies. “Eskom’s expenditure is not in line with NERSA’s decision. From the 2013/14 actuals to the 2019/20 projections, Eskom has consistently spent more than the NERSA decision. Eskom’s reasons for the over-expenditure are that the assumptions used in determining other costs do not use NERSA's decision as a base. The assumptions used considered the economic conditions at the time and other elements that influence other costs. This reason is considered unacceptable, as it does not take into account the Energy Regulator's decision."

In addition, the High Court, in its judgement on the review by Eskom of NERSA's FY2019 revenue decision, found NERSA's approach to employee benefit costs to be irrational. The summary of the court judgement on this matter is that NERSA cannot use the employee numbers ratio to sales volume in 2007 as a basis for determining employee benefit costs. The Court clarified that as an example, employees working in the construction of power stations, will not directly contribute to sales volume. However, in all subsequent decisions since the FY2019 decision, NERSA continues to make an inflation adjustment to the decisions judged to be irrational by the High Court. This process has continued for six financial years. The direct impact of such an incorrect approach requires adjustments to be made. This is illustrated in the figure below:

FIGURE 5: IMPACT OF NERSA DECISION IN FY2024



For FY2024, based on the Q2 projections, a total difference of R47bn in allowable revenue in that FY is experienced. The key differences are due to realistic Eskom Primary Energy costs are ~R25bn higher than NERSA decision. Operating costs are ~R22bn high than

NERSA decision. It is submitted that Eskom's application for FY 2024 was more closely aligned to the actuals that materialised. The implication of this is that just to keep abreast of these changes alone – will require an increase of approximately 10% in FY2026. It follows that to keep up with reality, further increases would be required related to FY2025. Then only can the FY2026 application be analysed. It is acknowledged that the FY 2024 was a challenging one for Eskom from an operational point of view.

3.5 Allowable revenue for each licensee

Eskom will continue to make ringfenced applications for the generation, NTCSA (transmission) and distribution licensee. This has been the practice since the MYPD 1 application. The MYPD methodology requires an average price increase to be determined at a Distribution level. The allowable revenue for Generation, NTCSA (Transmission) and Distribution are shown in the tables below. Due to the transition in the industry, it is incumbent upon NERSA to make ringfenced revenue decisions to facilitate the process. The NTCSA has been established as a regulated subsidiary of Eskom Holdings and has been operationalised on 1 July 2024. To respect this operational ringfencing the revenue related to the roles continuing to be performed by the NTCSA are included in their revenue requirement. The MYPD methodology is also complied with by means of cross referencing. The key difference is that IPP and International Purchases revenue is included in the NTCSA ringfenced revenue. These are then reflected as primary energy in accordance with the MYPD methodology.

TABLE 4: GENERATION ALLOWABLE REVENUE

Generation Allowable Revenue (R'millions)	AR	Formula	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Regulated Asset Base (RAB)	RAB		828 717	909 656	893 438	870 825	861 267
WACC %	ROA	X	4.00%	5.00%	6.00%	7.47%	9.69%
Returns			33 149	45 483	53 606	65 085	83 491
Primary energy	PE	+	125 030	129 493	124 190	125 267	128 681
International purchases	PE	+	-	-	-	-	-
IPPs	PE	+	-	-	-	-	-
Environmental levy	L&T	+	6 539	6 279	5 337	4 781	4 767
Carbon tax	L&T	+	5 534	21 291	19 895	19 274	20 948
Arrear debt	E	+	-	-	-	-	-
Employee Benefits	E	+	14 281	14 858	15 176	15 774	16 519
Maintenance	E	+	21 742	20 693	22 224	21 249	23 462
Other operating costs	E	+	19 070	19 487	20 027	20 912	21 016
Depreciation	D	+	53 054	55 406	61 921	62 927	67 812
Generation Allowable Revenue			**278 399**	**312 991**	**322 376**	**335 269**	**366 696**
Add: Approved RCA/court order for liquidation	RCA		13 241	10 961	-	-	-
TOTAL Generation Allowable Revenue	R'm		**291 640**	**323 952**	**322 376**	**335 269**	**366 696**

TABLE 5: NTCSA (TRANSMISSION) ALLOWABLE REVENUE

NTCSA Allowable Revenue (R'millions)	AR	Formula	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Regulated Asset Base (RAB)	RAB		116 667	146 325	176 193	211 428	248 072
WACC %	ROA	X	4.00%	5.00%	6.00%	7.47%	9.69%
Returns			4 667	7 316	10 572	15 802	24 048
Primary energy	PE	+	2 946	3 544	4 653	4 197	5 410
International purchases	PE	+	10 249	9 724	13 642	11 838	12 371
IPPs	PE	+	66 633	77 640	109 820	135 510	140 943
Environmental levy	L&T	+	-	-	-	-	-
Carbon tax	L&T	+	-	-	-	-	-
Arrear debt	E	+	-	-	-	-	-
Employee Benefits	E	+	4 423	4 634	4 822	5 023	5 253
Maintenance	E	+	1 675	1 857	1 968	2 039	2 114
Other operating costs	E	+	1 670	1 579	1 703	1 808	1 921
Depreciation	D	+	6 461	6 949	7 816	9 096	10 447
NTCSA Allowable revenue			**98 724**	**113 242**	**154 994**	**185 314**	**202 507**
Add: Approved RCA/court order for liquidation	RCA		1 802	1 636	-	-	-
TOTAL NTCSA Allowable Revenue	R'm		**100 526**	**114 878**	**154 994**	**185 314**	**202 507**

TABLE 6: DISTRIBUTION ALLOWABLE REVENUE

Distribution Allowable Revenue (R'millions)	AR	Formula	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Regulated Asset Base (RAB)	RAB		121 340	136 897	149 613	160 825	168 937
WACC %	ROA	X	4.00%	5.00%	6.00%	7.47%	9.69%
Returns			4 854	6 845	8 977	12 020	16 377
Primary energy	PE	+	24	25	26	27	28
International purchases	PE	+	13	13	14	15	15
IPPs	PE	+	-	-	-	-	-
Environmental levy	L&T	+	-	-	-	-	-
Carbon tax	L&T	+	-	-	-	-	-
Arrear debt	E	+	8 914	9 917	10 752	12 037	13 310
Employee Benefits	E	+	15 226	15 941	16 665	17 373	18 110
Maintenance	E	+	5 716	5 991	6 344	6 630	6 928
Other operating costs	E	+	8 422	8 851	9 275	9 655	10 058
IDM	IDM	+	1 798	807	653	682	712
Depreciation	D	+	6 710	6 732	6 702	6 670	6 709
Distribution Allowable Revenue			**51 676**	**55 122**	**59 408**	**65 109**	**72 246**
Add: Approved RCA/court order for liquidation	RCA		1 721	1 403	-	-	-
TOTAL Distribution Allowable Revenue	R'm		**53 396**	**56 526**	**59 408**	**65 109**	**72 246**

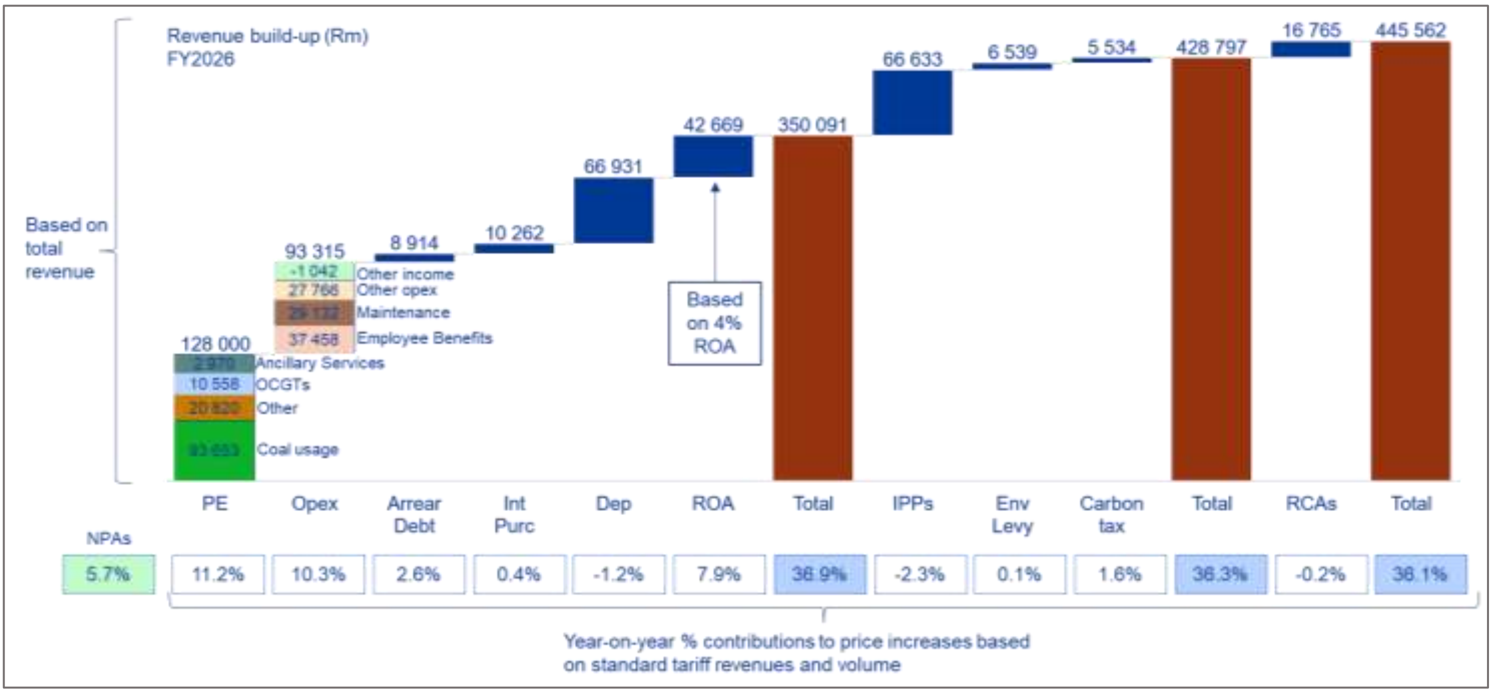
3.6 Indicative contributions to price increase in FY2026

To understand the 36% price increase in FY2026, it is necessary to understand the context even before the increased revenue from the latest projections is considered. In the FY2026, an additional 10 negotiated pricing agreements (NPAs) were included. These were concluded after the FY2025 revenue decision was made. These NPAs were approved by NERSA in accordance with the frameworks approved by the DMRE. The DMRE issued an

Interim Long-term Framework for NPAs in 2020, in terms of the EPP, with its primary objective being to provide qualifying industries with a globally competitive electricity tariff to mitigate against the loss of baseload electricity sales and negative impact on other customers and the economy. NPAs are structured to ensure the global competitiveness of the sector from an electricity price perspective. Implementation of a NPA, once approved by NERSA, will result in sustaining baseload sales volumes albeit at lower revenue levels. Eskom has implemented NPAs with customers in the aluminium, ferrochrome, and silicon carbide sectors totaling sales of ~ 23 TWh per annum. South Africa is better off with these customers in the sales base as the NPA structure ensures the relevant variable costs of electricity supply are covered by the tariff and a positive contribution to fixed cost. The typically flatter time-of-use and no seasonal differentiated NPA tariff could result in even usage throughout the year with a likely increase in sales which would partly offset the differential between the NPA tariff and standard tariff. In the absence of a NPA, the sustainability of these industries is in question which could result in potential cut-back in production or closure. This would result in additional upward electricity price pressure on the remainder of the customer base than would otherwise be the case due to loss of contributions to fixed costs. The impact of the introduction of these NPAs results a 5.7% price increase for standard tariff customers in FY2026.

Additionally, as explained, the previous NERSA decisions that did not closely align with what actually panned out, an approximate 10% price increase is experienced. This approximate 10% price increase is included in each of the relevant elements of the revenue application reflected below. It should be noted that once the adjustments have been made in the initial year, subsequent year increases are more tempered. The impact of the operational challenges experienced by Eskom during this financial year would need to be considered.

FIGURE 6: INDICATIVE CONTIBUTIONS TO PRICE INCREASES IN FY2026



Note: Primary Energy (PE) includes Ancillary Services; Int Purc - International Purchases; Dep – Depreciation; ROA – Return on Assets; IPPs– Independent Power Producers; Env Levy – Environmental Levy; RCAs – Regulatory Clearing Accounts

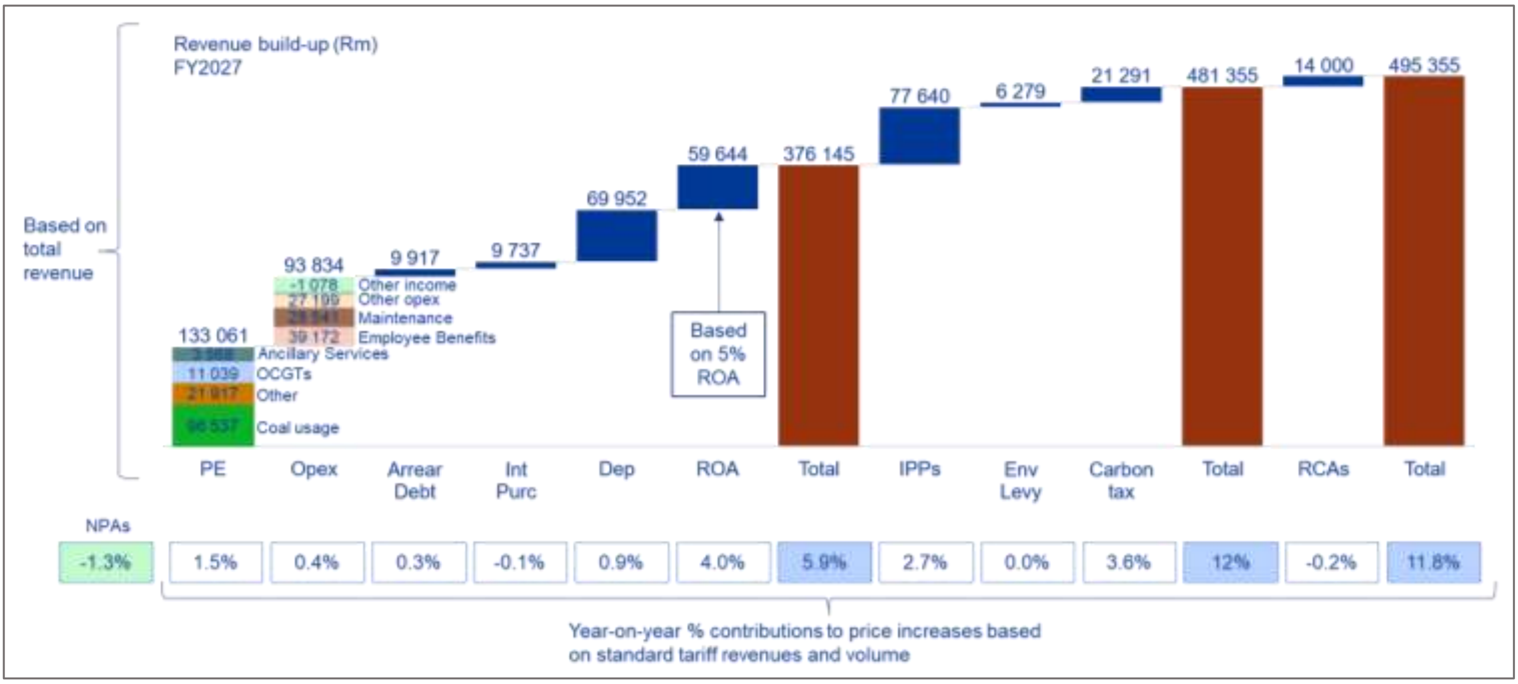
As observed in the figure above, the price increase is due mainly to the following:

- Primary energy costs – an increase in coal costs due to further dependence on coal-fired power stations to compensate for IPPs not materialising as envisaged. The Eskom OCGT fuel costs are maintained at a 6% load factor (as in the previous NERSA revenue decision), with a fuel price increase. The introduction of ancillary services from IPPs
- Operating costs – In addition to the expected increase from previous projections, an adjustment has to be made to set the operating costs at a realistic level
- Arrear debts – Have included as this is a normal aspect of any business. NERSA had not included in previous decision but had been included prior to MYPD 5
- Return on assets- In a bid to migrate towards cost reflectivity, the percentage ROA is being gradually increased. This is in line with a request by the Minister of Finance to allow for Eskom’s migration towards financial sustainability and lessening the burden on the fiscus
- Carbon Tax – Introduction of the carbon tax liability from 1 January 2026 (last quarter of FY2026) results in a contribution to the price increase. Further adjustments in FY2027 due to carbon tax liability for the entire financial year

3.7 Indicative contributions to price increases in FY2027

Once the key adjustments due to previous NERSA decisions have been considered and the impact of NPAs has already been considered in FY 2026, a price increase of 11.8% is required.

FIGURE 7: INDICATIVE CONTIBUTIONS TO PRICE INCREASES IN FY2027



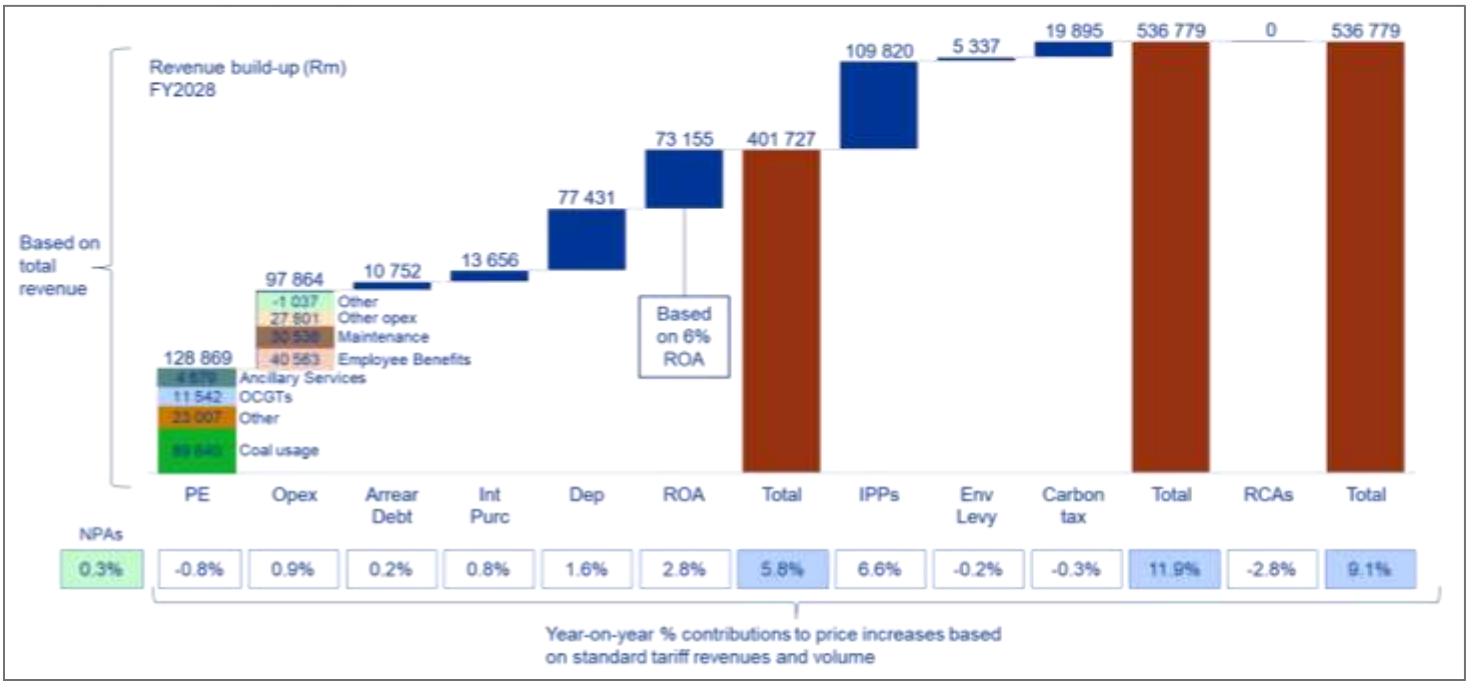
As observed in the figure above, the price increase is due mainly to the following:

- Primary energy costs – no significant increase
- Operating costs – no significant increase
- Return on assets – In a bid to continue migrating towards cost reflectivity, the percentage ROA is being gradually increased. This is in line with a request by the Minister of Finance to allow for Eskom's migration towards financial sustainability and lessening the burden on the fiscus.
- IPPs – Delayed IPP projects start coming on-line resulting in additional costs. This accounts for a 2.7% price increase. This equates to ~22% of the overall increase being applied for.
- Carbon Tax – Carbon tax liability for the entire financial year accounts for a 3.6% increase. This equates to over 30% of the overall increase being applied for

3.8 Indicative contributions to price increases in FY2028

The price increase for FY2028 is proposed at 9.1%.

FIGURE 8: INDICATIVE CONTIBUTIONS TO PRICE INCREASES IN FY2028



As observed in the figure above, the price increase is due mainly to the following:

- Primary energy costs – a decrease is observed
- Operating costs – no significant increase
- Return on assets- To continue migrating towards cost reflectivity, the percentage ROA is being gradually increased, in accordance with a request by the Minister of Finance to allow for Eskom's migration towards financial sustainability and lessening the burden on the fiscus
- IPPs – Significant increase due to further projects coming on-line resulting in a price increase of 6.6%. This equates to ~ 70% of the overall price increase being applied for

3.9 Revenue recovery

The recovery of the NPA revenue is in accordance with the contracts that have been concluded with the customers, as approved by NERSA. The revenue recovered from international customers would also be in accordance with the contracts with the international customers and utilities. Once the projected revenue for NPA and international customers is deducted from the total revenue, the remainder is recovered from Eskom standard tariff customers. This is in accordance with the manner in which NERSA makes its decisions.

TABLE 7: RECOVERY OF REVENUE

Revenue recovery (R'millions)	Decision FY2024	Decision FY2025	Application FY2026	Application FY2027	Application FY2028
Non standard tariff customers	18 734	17 203	37 835	46 775	49 683
Standard tariff (Incl RCA's)	334 963	334 963	407 728	448 581	487 095
MYPD6 Allowable Revenue	**353 697**	**352 167**	**445 563**	**495 355**	**536 778**

3.10 Electricity price impact during application period

The impact on the standard tariff price increase of the allowed revenue being applied for is reflected in the table below.

TABLE 8: STANDARD TARIFF AVERAGE PRICE INCREASE

Standard tariff price impact	Unit	Decision FY2024	Decision FY2025	Application FY2026	Application FY2027	Application FY2028
Standard tariff revenue	R'm	300 189	334 963	407 728	448 581	487 095
Standard tariff sales volumes	GWh	172 722	170 947	152 836	150 394	149 689
Standard tariff price	c/kWh	173.8	195.95	266.78	298.27	325.4
Standard tariff price adjustments	%	**18.65%**	**12.74%**	**36.15%**	**11.81%**	**9.10%**

The table above provides details on the proposed standard tariff price increases for each of the three MYPD 6 application years. The RCA decisions and court outcomes already made by NERSA are included in the standard tariff revenue when the standard tariff price adjustments are determined. Further implementation of RCA or court decisions by NERSA may impact the average price increase. The proposed price increases for the three years are 36.15%, 11.81% and 9.10% respectively.

4 Indicative Standard Tariff Increase

4.1 1 July Municipal (Local authority) tariff increase

Using the ERTSA methodology, the 36.15% average increase translates to a 1 July 2025 local-authority tariff increase of 43.55% to municipalities. Municipalities continue to pay at the FY2025 rates for the period 1 April 2024 to 30 June 2025 as per the MFMA. This equates to a price increase of 43.55% from 1 July 2025; a price increase of 3.36% from 1 July 2026 and a price increase of 11.07% from 1 July 2027. These decisions are subject to NERSA approval once the allowable revenue has been determined. It should be noted that due to the implementation of Municipal tariff increases not being aligned with the Eskom implementation dates, significant changes are experienced.

4.2 Eskom direct customers (Non-local authority tariff) increases

The 1 April 2025 non-municipal tariffs' increase including the Homelight 20A tariff, is the ERTSA annual average increase of 36.15% from 1 April 2025; a price increase of 11.81% from 1 April 2026 and a price increase of 9.10% from 1 April 2027.

4.3 Affordability subsidy charge increase

The affordability subsidy is 29.58% for FY2026, 25.42% for FY2027 and 22.07% for FY2028. This is based on similar NERSA decisions in the recent past. NERSA will make the final decision. In summary, the FY2026 to FY2028 average tariff category increases are set out in the table below.

TABLE 9: STANDARD TARIFF INCREASES

Customer categories	Decision FY2025	Application FY2026	Application FY2027	Application FY2028
Total Standard tariff	**12.74%**	**36.15%**	**11.81%**	**9.10%**
Municipal - 1 July	**12.72%**	**43.55%**	**3.36%**	**11.07%**
Eskom Direct:				
Key Industrial and urban				
Megaflex; Miniflex; Nightsave Urban; WEPS; Megaflex Gen				
* Other tariff charges	12.74%	36.15%	11.81%	9.10%
* Affordability subsidy charge (where applicable)	25.64%	29.58%	25.42%	22.07%
Other Urban				
Businessrate; Public Lighting	12.74%	36.15%	11.81%	9.10%
Rural				
Ruraflex; Nightsave Rural; Ruraflex Gen	12.74%	36.15%	11.81%	9.10%
Homelight 20A				
Block 1 (>0-350kWh)	12.74%	36.15%	11.81%	9.10%
Block 2 (>350kWh)	12.74%	36.15%	11.81%	9.10%
Homelight 60A	12.74%	36.15%	11.81%	9.10%
Homepower	12.74%	36.15%	11.81%	9.10%

4.4 Tariff structural changes during the MYPD 6 period

This revenue application does not deal with any potential Eskom tariff structural changes. A separate approval process for restructuring of tariffs will be made to NERSA for implementation from FY2026. The consultation in terms of MFMA requirements will also be undertaken separately. As NERSA approves changes to the tariff structures, NERSA will determine the timing of their implementation as well. A summary of the proposals and motivation for their urgent implementation is described here.

In pursuit of the country's tariff objectives, in line with the EPP, a Retail Tariff plan (RTP) was submitted to NERSA in 2020 and again in 2022. Both were not approved by NERSA in the main. Eskom will again submit an updated RTP in 2024 for approval. The significance of the proposed tariff structural changes allows for cost representative pricing that enables sustainability for all electricity supply industry participants, including private concerns.

The key reasons for the proposed changes include the need to align tariff rates with divisional costs, reflect the evolving energy industry, and ensure revenue recovery. The current tariff rates no longer accurately reflect the different services provided by Eskom. This misalignment arises from the application of average price increases, leading to tariff rates that do not align with the actual costs incurred in providing energy, network, and retail services. There is a need for charges that more accurately reflect the costs associated with each division.

Furthermore, the evolving nature of the energy industry necessitates the modernisation of tariff structures. Changes such as the increasing prevalence of customer-owned generation and the evolving patterns of grid usage require tariff structures that can adapt to these changes. Additionally, there is a need to ensure that wholesale purchase costs are accurately reflected in retail tariffs. This alignment is crucial to avoid a disconnect between the tariff structures, ensuring that the costs incurred in purchasing energy at the wholesale level are appropriately passed on to customers at the retail level. The evolution of tariff structures is also essential to protect the interests of all customers and to ensure the adequate recovery of NERSA-approved revenue by Eskom.

The proposed structural changes involve designing all charges using the updated NERSA approved forecast volumes, divisional cost splits, and cost allocation methods are as follows:

- Energy rates to reflect wholesale purchase structure where energy charges are split into variable time-of-use (TOU) charges, a fixed generation capacity charge and a legacy charge.
- Rationalising local-authority tariffs into three categories, Municflex for large power users (LPUs), Municrate for small power users (SPUs), and a Public Lighting tariff. This rationalisation will reduce the complexity simplifying the sales and revenue forecasting processes for Eskom and municipalities.
- Basing service charges on points of delivery (PODs) instead of the current per account to ensure fairness.
- Removing inclining block tariff (IBT) rates for Homepower tariffs by converting this tariff's charges to a cost-reflective tariff structure.

5 Sales Volumes

For the MYPD6 revenue application, one of the key assumptions is the latest available forecasted sales volumes. In accordance with the MYPD methodology, a revision of the forecasted sales volume to reflect the prevailing situation can be presented to NERSA for consideration. Eskom makes every effort to at least maintain its levels of sales and to increase sales, if possible. However, as is demonstrated below, the sales volume is an outcome of the economy of the country. Eskom is making every effort to address its operational environment to improve its availability within the constraints within which it operates. Thus, it is submitted that an improvement in the economic conditions in the country is a requirement for a likely improvement in the level of Eskom sales.

The forecasted sales volumes, as provided below are for all customer categories that are on standard tariffs, NPAs, and international sales. During the MYPD 6 period, the forecasted sales volume decline by 0.9%.

TABLE 10: TOTAL ESKOM SALES FROM FY2023 TO FY2030

Sales volumes (GWh)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Standard tariff sales	166 980	167 977	156 039	152 836	150 394	149 689	148 231	147 323
Year-on-year growth (%)		0.6%	-7.1%	-2.1%	-1.6%	-0.5%	-1.0%	-0.6%
Negotiated pricing agreement	10 413	10 440	22 679	22 581	22 625	22 713	22 564	22 591
Year-on-year growth (%)		0.3%	117.2%	-0.4%	0.2%	0.4%	-0.7%	0.1%
Total local sales	**177 392**	**178 416**	**178 717**	**175 417**	**173 019**	**172 403**	**170 796**	**169 914**
International Sales	11 357	9 619	10 355	10 235	10 235	10 265	10 235	10 235
Year-on-year growth (%)		-15.3%	7.7%	-1.2%	0.0%	0.3%	-0.3%	0.0%
Total Sales (incl. Internal	**188 749**	**188 035**	**189 072**	**185 652**	**183 254**	**182 668**	**181 031**	**180 149**
Year-on-year growth (%)		**-0.4%**	**0.6%**	**-1.8%**	**-1.3%**	**-0.3%**	**-0.9%**	**-0.5%**

Eskom's sales growth has trended downwards over the past three years, with the outlook remaining relatively depressed in the years ahead. Since 2006, sales have declined by an estimated average of 0.5% per year. The decline can generally be attributed to large power users as a result of low competitiveness, high ore extraction costs, and volatile commodity markets – particularly in the ferrochrome, steel, gold, and platinum industries.

It is important to emphasise that the South African economy had shown signs of significant distress prior to the onset of the pandemic and its associated lockdowns at the end of March 2020. Although South Africa is still viewed as an emerging market, several factors have contributed to the decline in underlying economic growth of the country. These include finite natural resources, low investor confidence, infrastructure bottlenecks, labour unrest, load shedding, rising local debt, and unemployment.

Given the numerous factors above, electricity sales growth is expected to decline over the next few years. However, Eskom hopes to grow sales over the medium term, supported by innovative products, solutions, and tariffs, in collaboration with customers to address their needs and aspirations.

5.1 Sales volume forecasting assumptions

The sales volume forecast is based on various assumptions reflecting the different types of customers' electricity needs and influences on diverse customer consumption profiles. Key assumptions include the GDP growth, commodity market performance and prices, demand response savings, weather conditions, customer projects, industrial action, and the impact of the leap year. The volume forecast does not include any future load shedding; it is a representation of the expected volume requirement in the market.

i. Gross domestic product (GDP)

Historical trends indicate that electricity consumption grows at a slower rate than the economy. In the sales volume forecast, the gap between sales growth and GDP is widening due to lower energy-intensive sales during the forecast years and migrating towards a greater service-oriented economy. In addition, several mines and large industrial customers are exploring alternative sources of energy. It is, therefore, assumed that the margin between GDP growth and electricity growth will continue to widen into the future. The figure below illustrates the anticipated gap between GDP and sales growth.

FIGURE 9: ACTUAL AND PROJECTED GDP VERSUS SALES GROWTH RATES

ii. Commodity prices

In 2022, commodity prices were volatile due to a range of factors, including global demand and supply disruptions. Ferrous metal commodity prices increased sharply in 2022, which led to an increase in sales in this sector. Customers ramped up production by switching on furnaces and reducing shutdowns during this period. Some customers brought back furnaces that had previously been shut down, which had a positive impact on sales. Prices are expected to stabilise in the short term. The stabilisation of prices, coupled with customers exploring alternative sources of energy, will lead to a decline in sales in this sector.

Platinum prices made a recovery after the COVID-19 pandemic, with high prices recorded in 2021 and 2022. As a result, platinum mines increased productivity, which resulted in higher sales. Platinum prices are expected to remain high in the short term and during the MYPD 6 period. This has been incorporated in the latest sales volumes forecast. Gold prices reached record highs in 2020, as the metal has remained a safe haven for investors. The price is expected to start stabilising in the short term. Gold mines are heavily reliant on the price, and sales in this sector are expected to decrease in the short term in line with the price of gold.

TABLE 11: COMMODITY PRICES (SOURCE: WORLD BANK COMMODITY OUTLOOK)

							Percent change from previous year		Differences in levels from October 2022 forecasts	
Commodity	Unit	2020	2021	2022	2023f	2024f	2023f	2024f	2023f	2024f
Metals and Minerals										
Aluminum	$/mt	1 704	2 473	2 705	2 400	2 450	-11.3	2.1	0	16
Copper	$/mt	6 174	9 317	8 822	8 500	8 000	-3.7	-5.9	1200	639
Iron ore	$/dmt	109.0	162.0	121.0	115.0	110.0	-5.2	-4.3	15	12
Lead	$/mt	1 825	2 200	2 151	2 100	2 000	-2.4	-4.8	200	83
Nickel	$/mt	13 787	18 465	25 834	22 000	20 000	-14.8	-9.1	1000	-708
Tin	$/mt	17 125	32 384	31 335	24 000	24 500	-23.4	2.1	2000	2243
Zinc	$/mt	2 266	3 003	3 481	2 800	2 700	-19.6	-3.6	0	-71
Precious Metals										
Gold	$/toz	1 770	1 800	1 801	1 900	1 750	5.5	-7.9	200	100
Silver	$/toz	20.5	25.2	21.8	23.0	22.0	5.5	-4.3	2.0	1.0
Platinum	$/toz	883	1 091	962	1 000	1 050	4.0	5.0	0	0

Source: World Bank (2023). Commodity Markets Outlook.

iii. Furnace load reduction in winter

It is assumed that a substantial amount of furnace load will not be utilised during winter due to the higher winter energy prices. As a result of the seasonal tariff, the majority of smelters usually perform maintenance on their furnaces during the winter months. Depending on trading conditions, furnace utilisation is assumed at around 90% in the summer months.

iv. Energy efficiency demand-side management (EEDSM)

The impact of EEDSM initiatives is embedded in the forecasted sales volumes, and it is, therefore, captured in the underlying historic sales volume base used in the trend analysis. The sales volume forecast assumption is that the historic EEDSM savings will continue during the application period.

v. Weather conditions

Residential and Agricultural sales are weather sensitive by nature. As customary, average weather conditions have been applied as a key input parameter to predict the sales of all the weather-sensitive customers.

vi. Leap year impact

Every fourth year, the month of February has 29 days, and this is recognised as a leap year. Consequently, there are additional sales in February 2028 due to the extra day.

vii. New customer projects

Only projects that have a high probability of start-up and have budget quotations accepted by customers are included in the sales forecast.

viii. Co-generation (co-gen)

The sales forecast also incorporates the co-gen capacity of large customers that have the capability to generate and wheel energy between each of their respective sister plants. It should be noted that their respective co-gen usage is dependent on plant availability and performance. In contrast, there are also co-gen customers that are envisaged to sell electricity to Eskom. These have been excluded from the sales volume forecast, as they are regarded as IPPs.

5.2 Forecasted sales volumes by customer category

The distributors' (municipal) sales volume of 45% reflects Eskom's sales to all municipalities and metros. In many municipal areas, the majority of sales are consumed by residential and commercial consumers. The industrial sector contributes 25% of Eskom sales, while mining constitutes a further 16%. The remaining sectors contribute to the residual 14% of Eskom sales. The customer categories used to derive the forecasted sales volumes are based on sectors as shown in the table below.

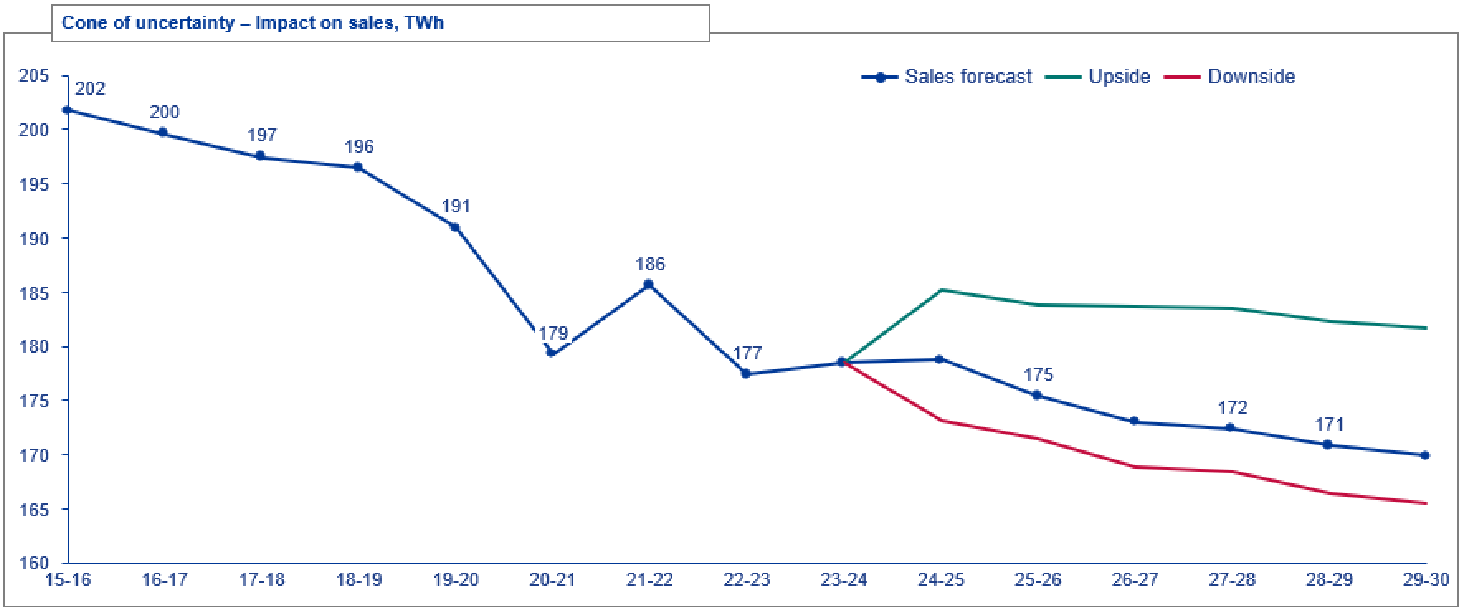
TABLE 12: MYPD 6 FORECASTED SALES PER SECTOR

Sales Volume (GWh)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Re-Distributors	79 480	80 122	80 266	77 905	75 695	75 093	74 104	73 506
Industrial	44 533	43 844	44 043	43 542	43 637	43 760	43 532	43 544
Mining	27 843	28 308	28 170	27 869	27 736	27 704	27 521	27 373
Commercial	9 376	9 885	9 666	9 654	9 597	9 568	9 489	9 416
Prepayment	6 342	5 886	6 413	6 379	6 350	6 328	6 294	6 269
Agricultural	4 785	5 305	5 111	5 072	5 038	5 018	4 978	4 956
Residential	2 625	2 550	2 594	2 549	2 508	2 470	2 425	2 383
Traction	1 668	1 679	1 627	1 621	1 631	1 634	1 628	1 643
Other	740	836	827	825	827	828	826	823
Local Sales	**177 392**	**178 416**	**178 717**	**175 417**	**173 019**	**172 403**	**170 796**	**169 914**
International (SAPP)	11 357	9 619	10 355	10 235	10 235	10 265	10 235	10 235
Total Eskom Sales	**188 749**	**188 035**	**189 072**	**185 652**	**183 254**	**182 668**	**181 031**	**180 149**

5.3 Uncertainty of the sales volume forecast

The demand for electricity is highly uncertain at the best of times. Eskom sales are expected to be negatively affected by the gradual transition to alternative energy sources as customers seek to have more stable and cleaner sources of energy. The figure below depicts the sales forecast, indicating the level of possible gains and losses.

FIGURE 10: TOTAL LOCAL SALES SHOWING THE CONE OF UNCERTAINTY



The tables below illustrate and quantify the various upside and downside factors associated with the above sales forecast over the MYPD 6 period. The factors are justifiable, given the volatile and unpredictable nature of elements largely beyond Eskom's control.

TABLE 13: POSSIBLE DECREASE IN ENERGY CONSUMPTION

Sales GWh						
Factor	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Low economic growth	(712)	(769)	(810)	(803)	(789)	(850)
Warmer winter, cooler summer, and high rainfall	(921)	(926)	(928)	(932)	(938)	(944)
Higher small-scale embedded generation	(171)	(216)	(243)	(268)	(290)	(296)
Higher photovoltaic (PV)	(283)	(398)	(512)	(627)	(741)	(791)
Customers downscaling/reducing load	(250)	(269)	(256)	(226)	(212)	(215)
Unplanned shutdowns	(150)	(150)	(150)	(150)	(150)	(150)
Industrial action	(62)	(62)	(62)	(62)	(62)	(62)
Higher non-technical losses	(278)	(280)	(283)	(285)	(288)	(290)
Supply constraints	(2 520)	(700)	(668)	(461)	(688)	(551)
Increased own generation	(202)	(202)	(202)	(202)	(202)	(202)
Conversions to prepaid	(29)	(28)	(28)	(27)	(27)	(26)
Total downside impact	**(5 578)**	**(4 001)**	**(4 143)**	**(4 044)**	**(4 387)**	**(4 378)**

The largest contributor is supply constraints, which can potentially reduce sales by more than 4 TWh in the application period. If customers invest in self-generation more aggressively, a further 3.5 TWh reduction will occur. Another significant variable that will have a negative impact on sales is lower economic growth. This could result in a 3 TWh reduction in sales. Since customers are exposed to a multitude of external factors, smaller risks are also inherent at sector level.

TABLE 14: POSSIBLE INCREASE IN ENERGY CONSUMPTION

Sales GWh						
Factor	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Higher economic growth	599	660	776	915	1 047	1 174
Colder winter, hotter summer, and low rainfall	1 157	1 158	1 160	1 164	1 170	1 176
Lower SSEG	14	60	61	63	65	67
No supply constraints	374	378	352	356	345	349
Free basic electricity (FBE)	16	21	22	22	22	22
Upscaling/New customer projects and connections	592	892	2 307	2 521	2 620	2 714
No shutdowns	200	200	200	200	200	200
Additional electric vehicles (EVs)	73	112	159	212	277	342
Ramping up Distribution (Dx) projects	50	45	45	45	24	24
Lower non-technical losses	231	260	299	294	355	434
Unavailability of own generation	2 392	2 392	2 392	2 392	2 392	2 392
Customer forecast materialising	527	1 100	1 100	1 100	1 100	1 100
Wheeling delays	251	1 163	1 833	1 843	1 842	1 842
Total upside impact	**6 476**	**8 441**	**10 706**	**11 127**	**11 459**	**11 836**

The figure in the table above highlights the upside or positive movement of sales in relation to the MYPD 6 forecast. This refers to a potential sales increase that could arise should certain conditions materialise. A key factor in this regard is that of new customer projects and connections that will require more consumption from Eskom. This implies that additional sales of 6 TWh could transpire should the customers' aspiration materialise and all new projects offtake from Eskom. A further favourable factor is the unavailability of own generation, which could result in 9.5 TWh additional sales.

5.4 Sales forecasting approach

There are various different influences on customers' current and future electricity consumption, determined by individual customers' need for electricity and substitutes to taking supply from Eskom. To practically capture this complex dynamic, the Eskom forecasting encapsulates differing sales assumptions by customer types that are the high-sales and lower-sales end users. For high-sales-volume customers, the sales forecasting assumptions comprise individual customer planning inputs. For the lower-consumption customers, the sales forecast is informed by historical trends, the weather, and relevant economic indicators.

Consequently, volume changes in the high-sales customer category require the application of an individual bottom-up approach in order to consider specific sales drivers, which include individual business plans, commodity prices, and the consideration of external economic factors.

The forecasting of international sales adopts the individual approach, given the country-specific drivers and the fact that the sales are exported.

Municipalities purchase in bulk from Eskom, distributing to the industrial and commercial sectors, with a greater part of supply to residential end users. Eskom bulk sales to municipalities differ from one municipality (or metro) to the next, as the purchase profile of each municipality is shaped by its individual customer-mix. Eskom, therefore, uses a combination of forecasting methodologies, combined with an individual consultation with the municipality, in line with the respective local government development plans. As municipalities, there are various aspects that have an impact on their respective electricity consumption profiles.

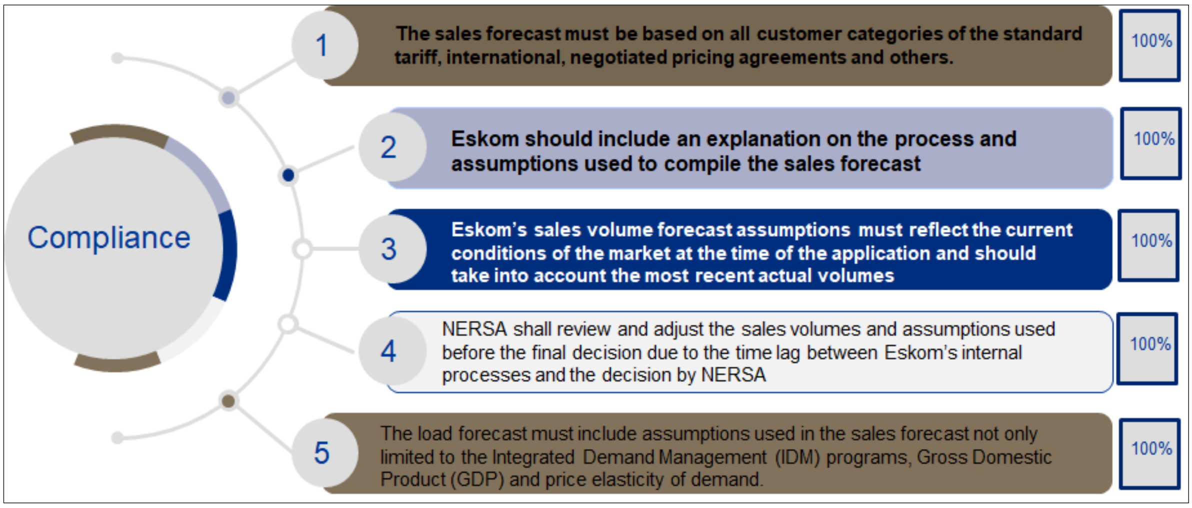
For the residential and commercial sectors, historical trends, the weather, and economic indicators are the primary indicators that inform the sales forecast.

5.5 Sales forecasting process

A five-step process, as depicted in the figure below, is followed to forecast Eskom electricity sales. This process includes the compilation of a six-year monthly detailed forecast, with a further four years at an annual level, using trends per sector. As the diagram depicts, the sales forecast is a bottom-up derived forecast.

Each of the nine Eskom provincial operating units concentrates on its top customers in detail, while the other customer sectors are forecasted at summary level to derive a six-year projection per month, with a further four years of annual numbers. Detailed analysis and rigorous validation processes follow to ensure consensus that the derived forecast is the most likely scenario, given the current information available.

FIGURE 11: AREAS OF COMPLIANCE IN PROVIDING THE MYPD FORECASTED SALES



Each Eskom Distribution operating unit (OU) attends to the customers that account for 80% of the revenue of that OU individually in great detail, engaging the customer executives and obtaining applicable information from the customers, while balancing this view with sectoral trends, the expected economic climate, and any other relevant information. It is clarified that, at this stage, the proposed price increase that NERSA will determine is not known.

6 Energy Wheel

Eskom utilises an energy wheel to ensure that a balance between the demand and supply is planned for. The Energy Wheel is a summary of the balance between the Eskom demand and supply of energy. The demand side of the Energy Wheel portrays the total projected Eskom sales which are made up of Distribution national sales and Export sales, inclusive of the transmission and distribution losses. This makes up the total amount of energy that needs to be produced to supply customers' needs and is the starting point of the production planning process. This energy forecast has been discounted with the impact of demand side management options.

The supply side of the Energy Wheel shows the volume of electricity that is required from local and international power stations as well as IPPs to be supplied to Eskom's distribution and export points (including the losses) to meet the demand.

FIGURE 12: ENERGY WHEEL FY2026 (ALL FIGURES IN GWH)

Generation of Electricity	Application
Generation	175 993
OCGT	1 266
Pumping	(5 539)
IPP	31 364
Total	**203 084**

Available for Distribution	Application
Generation (incl IPPs)	208 623
International	6 601
Wheeling	2 723
Sub Total	**217 948**
Pumping	(5 539)
Total	**212 409**

Total Imports	Application
International Purchases	6 601
Wheeling	2 723
Total	**9 324**

Total Exports	Application
International Sales	10 235
Wheeling	2 723
Total	**12 958**

South African Power Pool

Internal Use	Application
Generated	0
Internal Use	380
Total	**380**

Demand	Application
Sales	185 272
Losses	24 034
Internal	380
Generated	0
Wheeling	2 723
Total	**212 409**

External Sales	Application
Local	174 929
Dx International	108
International	10 235
Total	**185 272**[1]

Technical & Other Losses	Application
Distribution	18 585
Transmission	5 449
Total	**24 034**

Technical & Other Losses - %	Application
Distribution	9.56%
Transmission	2.50%

1 Total External Dx sales excludes internal sales and includes international sales

FIGURE 13: ENERGY WHEEL FY2027 (ALL FIGURES IN GWH)

Generation of Electricity

	Application
Generation	168 891
OCGT	1 266
Pumping	(5 294)
IPP	35 214
Total	**200 078**

Available for Distribution

	Application
Generation (incl IPPs)	205 371
International	6 449
Wheeling	2 723
Sub Total	**214 543**
Pumping	(5 294)
Total	**209 249**

Total Imports

	Application
International Purchases	6 449
Wheeling	2 723
Total	**9 171**

Total Exports

	Application
International Sales	10 235
Wheeling	2 723
Total	**12 958**

South African Power Pool

Internal Use

	Application
Generated	0
Internal Use	379
Total	**379**

Demand

	Application
Sales	182 875
Losses	23 272
Internal	379
Generated	0
Wheeling	2 723
Total	**209 249**

External Sales

	Application
Local	172 532
Dx International	108
International	10 235
Total	**182 875**[1]

Technical & Other Losses

	Application
Distribution	17 908
Transmission	5 364
Total	**23 272**

Technical & Other Losses - %

	Application
Distribution	9.36%
Transmission	2.50%

1 Total External Dx sales excludes internal sales and includes international sales

FIGURE 14: ENERGY WHEEL FY2028 (ALL FIGURES IN GWH)

Generation of Electricity	Application
Generation	144 535
OCGT	1 266
Pumping	(5 464)
IPP	57 259
Total	**197 596**

Available for Distribution	Application
Generation (incl IPPs)	203 060
International	8 573
Wheeling	2 831
Sub Total	**214 463**
Pumping	(5 464)
Total	**209 000**

Total Imports	Application
International Purchases	8 573
Wheeling	2 831
Total	**11 403**

Total Exports	Application
International Sales	10 265
Wheeling	2 831
Total	**13 096**

South African Power Pool

Internal Use	Application
Generated	0
Internal Use	379
Total	**379**

Demand	Application
Sales	182 289
Losses	23 501
Internal	379
Generated	0
Wheeling	2 831
Total	**209 000**

External Sales	Application
Local	171 916
Dx International	108
International	10 265
Total	**182 289**[1]

Technical & Other Losses	Application
Distribution	18 140
Transmission	5 362
Total	**23 501**

Technical & Other Losses - %	Application
Distribution	9.50%
Transmission	2.50%

1 Total External Dx sales excludes internal sales and includes international sales

7 Production Plan

7.1 Implementation of the IRP 2019

It is evident from the two tables below, that a significant amount of generating capacity that was to be commissioned did not materialise. In the period 2019 to 2023 – over 8 000MW of capacity was not made available to the system. In addition, it is likely that further capacity that was expected to be made available timeously, will not occur. This includes the 1 500MW of coal and 3 000MW of gas that could have been dispatchable. Furthermore, no significant attempt has been made for any alternate new build capacity. The inability to deliver on specific programmes was known in advance, without sufficient contingencies being put in place. The practical outcome of the lack of new build delivery has resulted in further pressure being put on Eskom generators to fill the gap. This has probably resulted in the country experiencing higher levels of load shedding in the recent past.

TABLE 15 : CAPACITY IN IRP 2019

IRP Capacity (MW)	PV	Wind	Gas	Storage	Coal	Hydro	DEG	RMIPPP
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	1000	1600	0	513	0	0	0	2000
2023	1000	1600	0	0	750	0	500	0
2024	0	1600	1000	0	0	0	500	0
2025	1000	1600	0	0	0	0	500	0
2026	0	1600	0	0	0	0	500	0
2027	0	1600	2000	0	750	0	500	0
2028	1000	1600	0	0	0	0	500	0
2029	1000	1600	0	0	0	0	500	0
2030	1000	1600	0	0	0	2500	500	0

TABLE 16 : CAPACITY REALISED

Actual Capacity Realised (MW)	PV	Wind	Gas	Storage	Coal	Hydro	DEG	RMIPPP
2019	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0
2023	0	0	0	200	0	0	0	150

The FY2023 RCA submission further illustrates that Eskom's power stations need to make difficult operational decisions that compensate for the unavailability of IPPs. Eskom exceeded the energy from coal fired power plants originally assumed and achieved over 99.9% of the updated production plan. In its decision (Feb 2022), NERSA arbitrarily increased the energy requirement from Eskom coal fired power stations to meet the further shortfall in IPP energy.

In the NERSA FY2025 revenue decision NERSA approved the exact same projected sales volumes, as submitted by Eskom. This implies that the demand that needs to be met by the supply is the same. However, NERSA's proposed production plan does not meet the energy required. NERSA plans for approximately 5 TWh less than projected. In essence, NERSA determines that the risk mitigation plan (IPPs) will not be delivered in this timeframe. However, a significant part of the shortfall is not being met by any alternative source. This corresponds to approximately 2.25% of the total energy. In addition, at the production planning stage, NERSA allows for a 10% load factor for OCGTs. This equates to 2 110 GWh of energy. Eskom had planned for 12% load factor – which equates to approximately 2 539 GWh of energy. However, the revenue allowed only caters for a 6% load factor for OCGTs. This equates to 1 266 GWh for the financial year. Thus, a further gap of 844 GWh needs to be filled. NERSA allowed for a 12% load factor for the OCGT plants of IPPs. This implies that the IPP plants are required to be dispatched at a higher rate than the Eskom OCGT plants.

This trend continues in the MYPD 6 application. The difference in energy to be secured from IPPs has dropped tremendously from what was originally envisaged by the Government Departments. This corresponds to shortfalls of approximately 26 TWh (FY26), 42 TWh (FY27) and 33 TWh (FY28). This is approximately 12% (FY26), 20% (FY27) and 15% (FY28) of the total energy supply that Eskom needs to accommodate. This has far-reaching impacts on Eskom's operations, and by implication, efficient costs.

7.2 Production Plan Objective

The main objective of Production Planning is to ensure optimal output from available power stations to reliably meet the system demand at least cost, while recognising Generation, primary energy, and any other technical constraints. The key principle for Production Planning is for the merit order dispatch to be maintained within known constraints. Constraints include emissions, coal shortages/surplus, water shortages and any other technical constraints.

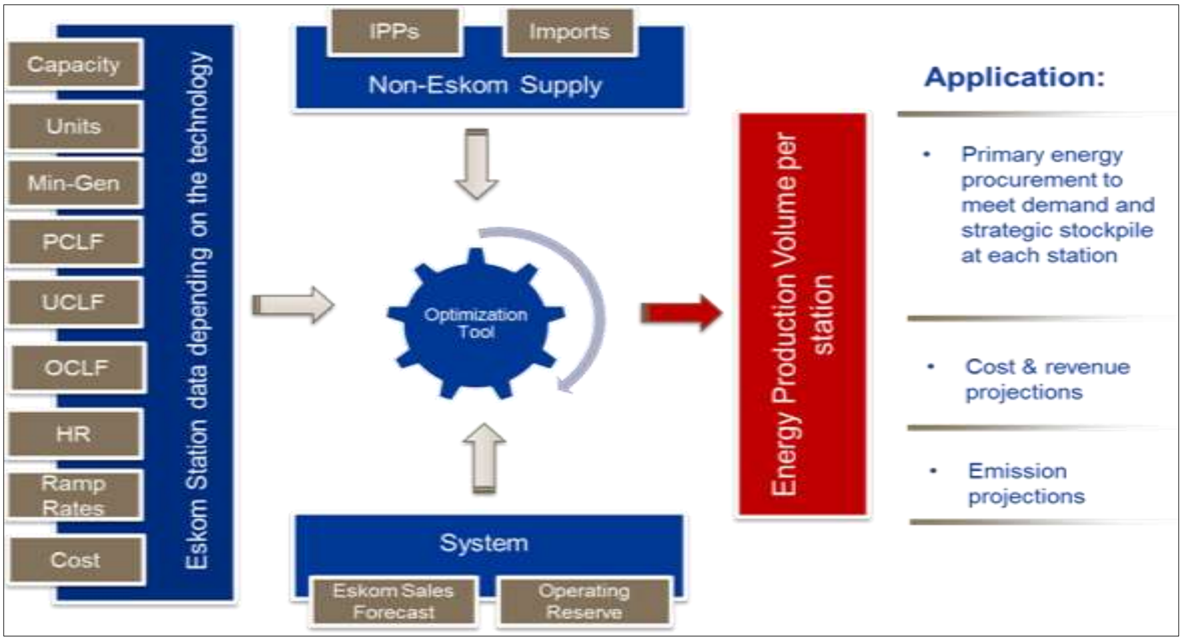
Merit order dispatch is derived from the primary energy costs (mainly coal and diesel cost) as well as power station burn rates (station efficiency and coal quality) resulting in an energy cost (R/MWh) ranking per station from the cheapest to the most expensive. Coal and diesel costs are the major contributors to the variable cost of electricity production, and on its own, results in an accurate relative merit order and optimum dispatch.

The Production Plan outcome provides the expected production level at each power station which is the basis of the Primary Energy (i.e. Coal, Water, Sorbent, Nuclear, OCGT, Start-up Fuel, Water Treatment, Coal Handling, Carbon Tax and Environmental Levy) cost projections.

7.3 Production Plan process

The Production Plan is optimised using a simulation tool called the Plexos Energy Model. Plexos is a simulation tool that uses data handling, mathematical programming and stochastic optimisation techniques to provide an analytical framework for power market analysis. It is able to optimally dispatch generating units based on user defined constraints and respecting technical limits. This modelling tool determines the optimal dispatch of generating resources within given system constraints to meet the power demand from a single period to daily, weekly, monthly or annual timeframes.

FIGURE 15: OVERALL PRODUCTION PLANNING PROCESS



The process for Production Planning is depicted in the figure above. The inputs to the optimisation tool include hourly demand forecast, planned and unplanned maintenance, ramp rates, variable cost (coal and diesel cost), capacity, number of units per station, minimum generation, operating reserve requirements, commercial operations date for

Generation new build, import capacity, IPPs and all other parameters required for modelling the system.

Generators are dispatched from the lowest variable cost to the most expensive generator in the system. Nuclear power station (Koeberg) is a must run station and it is always dispatched to its maximum capacity available. The cycle efficiency of a pumped storage scheme (Drakensberg, Palmiet and Ingula), system costs (based on pumping requirements) and the historical generating patterns of existing schemes determine their generation pattern, hence they are given minimum load factors. They are modelled such that their top reservoirs must be full at the beginning of every week.

Gariep and Vanderkloof generate as per agreement between Department of Water Affairs and Generation Peaking department in the short-term. The full capacity of these stations is thus not always available in all hours; they can only be dispatched for an agreed number of hours per day. However, for medium-to-long term, monthly energy is projected from historical production patterns. Hydro power stations will be dispatched as required by the system up to the monthly projected energy.

The OCGTs are constrained by possible fuel deliveries per month. For Eskom OCGTs, the total fuel delivery constraint for all sites is equivalent to 650 GWh per month which is based on the historical maximum energy ever produced in a month. The IPPs are constrained to maximum 25% load factor per month due to fuel delivery limitations. Eskom and IPP OCGTs are optimized based on their variable cost as an emergency supply and are constrained to produce at least 6% load factor per annum to cater for any unforeseen event occurring on the system.

Coal fired power stations are modelled as per their technical parameters which include number of units, units' end of plant life, minimum generation levels, ramp rates, energy cost, availability and other characteristics required by the tool. Dispatch of power stations will be based on their energy cost. Expensive power stations are expected to produce less if the system is not constrained.

Non-Eskom generators (Imports and IPPs) are modelled as contracted to Eskom. Renewable IPPs are modelled using their hourly profiles for each technology to meet projected monthly/annual energy. Imports and IPPs are forced in the model to be dispatched first and the remainder of the energy is met by Eskom generators.

7.4 Production Plan assumptions

The plan was developed based on the Eskom Generation continued operations strategy which intends to operate all the currently operating units at Grootvlei, Hendrina, Camden, Arnot and Kriel until FY2030. Therefore, all stations/units are kept operational until FY2030 which includes Acacia and Port Rex. It must be noted that the useful life of the power station is not determined by age but also by factors such as economic viability and strategic considerations. The main assumptions include:

7.4.1 Generating Capacity

Generation currently operates 46 686 MW (nominal capacity) of commercial fleet (excluding 100 MW of Sere), of which 39 099 MW is coal-fired. The rest is made up of 1 854 MW nuclear, 2 409 MW of gas turbines, 600 MW hydro and 2 724 MW pumped storage.

7.4.2 Generation new build capacity

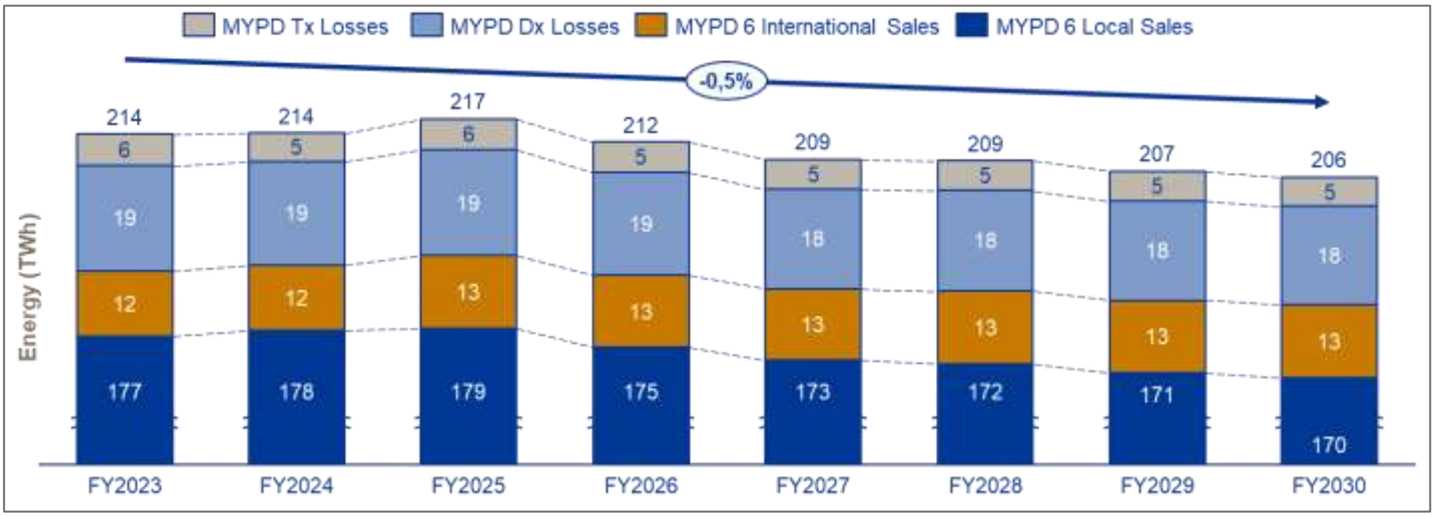
Eskom new build dates assumed in the production plan inputs are based on latest forecast of commercial operational dates. The only remaining unit to be commercialised is Kusile Unit 6 in February 2025.

7.4.3 Energy Forecast assumption

For production planning purposes, the source of the energy forecast is the Energy Wheel Diagram. The forecast provides an indication of the energy sales from international exports, Distribution and Transmission national sales per month and/or annum. Distribution and Transmission line losses are added to these sales to arrive at the total energy forecast for a month or year.

The production planning model requires an hourly demand forecast for each of the years being studied. The hourly demand forecast is developed from the Energy Wheel Diagram's monthly or annual energies and the IRP hourly profile as a reference of hourly demands. The hourly demands of the reference profile are scaled until the given monthly or annual energy figures are satisfied. The peak demands for each of the years of the study period are also the result of this scaling process. The figure below, shows net energy forecast.

FIGURE 16: ENERGY FORECAST AS PER WHEEL DIAGRAM



7.4.4 Non-Eskom Generation supply assumptions

Non-Eskom generation supply includes IPPs and International imports. The International imports consist mainly of Cahora Bassa. The unavailability of Cahora Bassa in certain months is due mainly to outages. IPP initiatives are included up to Bid Window 8 which includes gas programme, risk mitigation programme, emergency generation, standard offer, and battery storage. Eskom generators supply the balance after imports and IPPs have been utilised.

TABLE 17: INTERNATIONAL IMPORTS AND INDEPENDENT POWER PRODUCERS (GWH)

Non Eskom (GWh)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Purchases	8 654	9 295	9 776	6 601	6 449	8 573	6 930	6 930
Wheeling	2 904	2 152	2 826	2 723	2 723	2 831	2 826	2 826
IPP	17 957	22 972	23 856	31 364	35 214	57 259	71 610	70 952

7.4.5 Generation Plant Performance

Eskom Plant Performance assumptions data determine the availability of the generating plant, its technical performance and the constraints within which the available plant will be operated. These data include unplanned capability loss factor (UCLF) estimates, other capability loss factor (OCLF) estimates, planned capability loss factor (PCLF) and any other specified technical constraints. The generation plant performance Energy Availability Factor (EAF) is projected to improve during the MYPD 6 period as indicated in the table below.

TABLE 18: GENERATION TECHNICAL PERFORMANCE

Generation Technical performance (%)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Energy Availability Factor (EAF)	56.5	56.0	61.0	63.0	64.0	65.0	66.0	67.0
Planned Capacity Loss Factor (PCLF)	10.4	11.5	10.5	10.5	10.5	10.5	10.5	10.5
Unplanned Capacity Loss Factor (UCLF)	31.5	31.1	27.0	25.0	24.0	23.0	22.0	21.0
Other Capacity Loss Factor (OCLF)	1.6	1.4	1.5	1.5	1.5	1.5	1.5	1.5

It must be noted that the plan assumes a low OCLF as this is based on assuming adequate coal stockpiles at power stations so as to deal with supplier shortfalls, strikes, weather conditions, etc.

7.4.6 OCGT Usage

Eskom Generation and IPP OCGTs are optimised but constrained to a load factor of 6% per annum.

7.4.7 Production Plan Outcomes

With the above assumptions, the Production Plan shows that the system will be transitioning to an adequate system by FY2027. This is evident by observing the declining system Energy Utilization Factor (EUF). As a result, some higher production-cost power stations (based on merit order informed by primary energy cost) are expected to be utilised less to meet the demand. The system dynamics can change at any time due to inherent risks such as unavailability or delay of IPP projects, sudden increase in demand, and lower than expected plant performance among other risks. These higher production-cost power stations will serve as the risk mitigation since they can be utilised more in the instances of capacity shortages. Also based on the current assumptions, both IPP and Generation OCGTs are kept at 6% load factor per annum for the entire planning cycle for a quick response in the system.

Utilising certain units to manage the system should be an operational decision based on system health and security, Scheduling and Dispatch Rules (SDR), grid stability and technical capability of units at that particular period. SDR stipulates that "*System Operator shall Schedule and Dispatch generation and demand-side resources to least cost whilst maintaining prescribed system security*". SDR further states that the "*generator should take into account all prevailing constraints, technical and/or economical*". The table below shows the detailed production per technology for the MYPD 6 period.

TABLE 19: ENERGY PRODUCTION PER PLANT MIX (GWH)

Electricity output GWh	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Power sent out by Eskom stations, GWh (net)	191 307	183 900	186 036	177 260	170 156	145 802	131 296	130 594
Coal-fired stations (incl. Pre-Commissioning), GWh (net)	171 131	167 177	170 108	159 704	149 556	126 241	110 616	109 723
Hydroelectric stations, GWh (net)	3 060	945	832	779	616	830	830	696
Pumped storage stations, GWh (net)	4 081	4 793	4 522	4 242	4 055	4 188	4 224	4 002
Gas turbine stations, GWh (net)	3 018	2 539	1 266	1 266	1 266	1 266	1 266	1 266
Wind energy, GWh (net)	214	314	307	304	304	304	304	308
Nuclear power station, GWh (net)	9 803	8 131	9 001	10 965	14 359	12 973	14 056	14 599
IPP purchases, GWh	17 957	22 972	23 856	31 364	35 214	57 259	71 610	70 952
Wheeling, GWh	2 904	2 152	2 826	2 723	2 723	2 831	2 826	2 826
Energy imports from SADC countries, GWh	8 654	9 295	9 776	6 601	6 449	8 573	6 930	6 930
Total Gross Production , GWh	**220 822**	**218 320**	**222 493**	**217 948**	**214 543**	**214 464**	**212 662**	**211 301**
Less Pumping	5 504	6 469	5 901	5 539	5 294	5 464	5 517	5 225
Total Net Production , GWh	**215 318**	**211 851**	**216 592**	**212 409**	**209 249**	**209 000**	**207 145**	**206 077**

7.5 Conclusion on the production plan

As can be observed by the results in the table above, the Generation energy sent out drops to 209 000 GWh in FY2028. The IPPs’ market share will increase over the period. As the plant availability stabilises and new capacity is added onto the grid, energy growth remains stagnant and plant utilisation will drop.

7.6 Stress test on Production Plan

The Production Plan used for the MYPD 6 application is based on a plant availability of between 63% in FY2026 to 65% in FY2028. However, the projected availability for FY2024 is an EAF of 56%. Availability of the Generation fleet is one of many assumptions in the Production Plan. Others include the energy forecast and changes in the Generation and IPP new build programmes.

Due to uncertainties in these Production Planning assumptions, a risk impact assessment on the system was conducted. The assumptions for this risk assessment (i.e Stress Test) include higher sales, and an EAF of between 57% in FY2026 to 59% in FY2028, and a delay in IPP new capacity. All other assumptions remain the same as the MYPD 6 Production Plan.

The impact of the stress test assumptions include Eskom OCGTs are expected to be further utilised in the FY2026 (14% load factor) and FY2027 (6.9% load factor); rotational load shedding is expected to be implemented in FY2026. It is important to note that this outcome is subject to the stress tested production plan assumptions materialising and associated funding obtained to execute required maintenance. The system Energy Utilization Factor is projected to drop from 80% in FY2025 to 59% in FY2030 as the IPPs come online based on delayed dates and energy forecast dropping over-time. The system load factor is projected to follow the same trend.

7.7 Energy Losses

The nature of transporting electricity from generator to the end-users involves losses in energy volumes (electrical or technical losses) that reduce the amount of electricity volumes available for sale to end-customers. In addition, other energy losses may occur due to non-metered usage related to electricity theft (non-technical losses). The representation of the measure for the levels of the combined total technical and non-technical losses is by way of loss factors. As required by the MYPD methodology, the updated Eskom loss factors calculated as per the Tariff grid code are included.

Energy loss is an inherent risk in the electricity business and utilities globally are addressing this issue. Energy losses are incurred when energy is transferred from the suppliers to the customers through the network. This energy lost, is approximately equal to the difference between the energy supplied and the energy consumed.

- Transmission losses are determined by the difference between energy injected onto the transmission grid and energy off-take at main transmission substations (MTS) and interconnection points.
- Distribution losses are determined by the difference between energy purchased (measured at main transmission substations) and energy sold to all Distribution customers.

Energy loss has a direct effect and increases generation requirements (both capacity and energy volumes) and thus primary energy costs.

8 Weighted Average Cost of Capital (WACC)

The weighted average cost of capital (WACC) component of the building blocks to the allowable revenue formula:

$AR=(RAB \times WACC)+E+PE+D+R\&D+IDM \pm SQI+L\&T \pm RCA$

The WACC is determined in accordance with the requirements of the MYPD methodology. It is clarified that even though the determination for the WACC is made, it is not implemented to the full extent in this MYPD 6 revenue application.

Electricity production and distribution is a capital or asset intensive industry i.e. significant up-front capital investment is required in order to acquire the assets which are needed to produce, transmit and distribute the electricity. The capital invested to acquire an asset is thereafter recovered over the full operational life of an asset. The cost of such capital is an inherent cost of the production of electricity and must therefore be recovered through the price of electricity in order for the industry be sustainable, which includes meeting its debt obligations. The capital structure consists of a weighting of equity and debt with Eskom currently at 60% for debt and 40% for equity.

Both debt and equity come at a cost and thus the weighted cost of capital (WACC) is utilised to determine the funding costs for organisations. The NERSA regulatory methodology requires the earning of returns on assets (ROA). These are in lieu of interest costs, which are not separately recovered as a cost component.

In the recent past there have been several developments that have transpired which negatively affected Eskom’s cost of capital. Credit rating downgrades by Standard & Poor’s, Moody’s and Fitch rating agencies coupled with sovereign downgrades has placed further upward pressures on funding costs. As a result of this the state has had to inject a significant amount of equity to sustain the business.

TABLE 20 : COST OF CAPITAL

Weighted Average Cost of Capital	Debt	Equity	WACC
Costs - Nominal	20.52%	13.56%	
Weight	60%	40%	
WACC nominal pre-tax			**16.30%**
Costs - Real	14.78%	8.15%	
Weight	60%	40%	
Inflation		5%	
WACC real pre-tax			**10.80%**

Changes in the WACC from MYPD 5 are as a result of:

- The Eskom capital structure (previously 70% debt and 30% equity).
- Increase in the risk-free rate.
- Increase in the inflation target.

During the revenue application only a portion of the WACC is proposed. As alluded to in various parts of this submission, Eskom is only requesting a return on assets that allows for migration of the average price of electricity to a level that corresponds to the efficient cost of electricity. Further details are elaborated in the section on return on assets of this submission.

9 Regulatory Asset Base, Depreciation and Return

The Regulatory Asset Base (RAB) is defined as assets of the regulated business that is used or usable in the production of the regulatory services. The MYPD methodology specifies that the RAB of the regulated business operations must only include assets necessary for the provision of regulated services based on the net depreciated value (residual value) of allowable fixed assets necessary to allow the utility reasonable return to be financially viable and sustainable while preventing unreasonable price volatility.

Depreciation and return on the RAB provides the regulatory mechanisms under which capital investment costs are recovered on a cost reflective basis over the course of its regulatory economic life. Hence capital expenditure is not a separate cost item in the revenue regulatory formula.

In this revenue application, Eskom is required to apply for the following:

- Depreciation on the commissioned assets, in accordance with the method prescribed by the MYPD methodology. Depreciation is calculated on revalued assets as at 31 March 2020, assets commissioned since 31 March 2020 and asset purchases.
- Return on assets is calculated on all assets as shown in the table below.

TABLE 21: REGULATORY ASSET BASE (RAB) SUMMARY

REGULATORY ASSET BASE (R'million)	Decision FY2024	Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Depreciated Replacement Costs (DRC)	857 384	801 373	767 205	716 214	666 052	617 218	569 919
Assets Tansferred to Commercial Operations after 2020	64 320	42 748	279 632	341 859	409 510	465 862	549 479
Work Under Construction (WUC)	62 077	50 647	76 530	100 993	109 584	103 617	116 995
Net Working Capital	57 544	69 057	69 369	51 267	59 757	70 094	76 817
Assets Purchases	516	521	3 981	4 437	4 734	4 432	4 199
Assets funded upfront by customers	(14 706)	(14 791)	(12 822)	(12 910)	(13 008)	(11 696)	(10 382)
Closing RAB	**1 027 136**	**949 554**	**1 183 895**	**1 201 861**	**1 236 628**	**1 249 527**	**1 307 026**
Average RAB		**988 345**	**1 066 724**	**1 192 878**	**1 219 244**	**1 243 078**	**1 278 277**

9.1 Regulatory Asset base components:

In accordance with the MYPD methodology, the regulatory asset base is comprised of the following:

- Depreciated replacement cost assets: these are assets as per the March 2020 asset valuation. The valuation includes assets already in use in the generation, transmission and distribution of electricity as at 31 March 2020. All other assets in construction are not included in the valuation but rather in the Work under construction (WUC).

- Assets transferred to commercial operations: This refers to generation, distribution and transmission assets transferred into Commercial Operation subsequent to the 2020 asset valuation. Once commissioned, these assets are then depreciated by dividing the cost of the asset over the number of years that the asset is to be used for i.e., the useful life of the asset.

- Work under construction (WUC): In accordance with the MYPD methodology, for assets that constitute the 'creation of additional capacity', the capital project expenditures or WUC values (excluding Interest During Construction) incurred prior to the assets being placed in Commercial Operation (CO) are included in the RAB and earn a rate of return.

- Net working capital: This includes trade and other receivables, inventory and future fuel less trade and other payables.

- Asset purchases: all movable items that are purchased and ready to be used are included in this category e.g., Equipment and vehicles, production equipment etc.

9.2 Depreciated replacement costs

The roll forward of the depreciated replacement costs for MYPD 6 as shown below is based on MYPD 5 approved values. The depreciation is based on the remaining useful life.

TABLE 22: FIXED ASSETS – DEPRECIATED REPLACEMENT COSTS

Fixed assets:- DRC Values (R'million)	FY2024	FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Opening balance	427 094	876 565	820 553	767 205	716 214	666 052	617 218
Inflation on opening balance	-	-	-	-	-	1	2
Land & Buildings	-	-	-	-	-	-	-
Revaluation reserves	507 817	-	-	-	-	-	-
Transfers from Work Under Construction (WUC	-	-	-	-	-	-	-
Depreciation	(58 346)	(56 012)	(53 348)	(50 991)	(50 162)	(48 835)	(47 301)
Closing asset values	**876 565**	**820 553**	**767 205**	**716 214**	**666 052**	**617 218**	**569 919**

9.3 Work under construction (WUC)

In terms of the MYPD methodology the criteria for inclusion of WUC into the RAB is for those assets that are for the creation of additional generation, transmission and distribution capacity and are defined as follows:

- **Expansion –** this is capital expenditure to create additional capacity to meet the future anticipated energy demand forecast.
- **Upgrade –** this is capital expenditure incurred to ensure that the current and future energy demand forecast is met.
- **Replacement –** this is capital expenditure to replace assets that have reached the end of their useful life in order to continue meeting the current demand.
- **Environmental legislative requirements –** this is capital expenditure incurred to ensure that the licensing condition is maintained thereby continuing to meet the current energy demand forecast.

A WUC in essence refers to the capital expenditure being undertaken and meets the criteria referred to above for inclusion in the RAB. In terms of the MYPD methodology, the WUC balance is required to earn a return on assets but is not depreciated until assets are transferred to Commercial Operation (CO). Only upon CO do these assets incur depreciation costs.

9.4 Depreciation

The depreciation is the cost of usage over the life of the asset. This is generally a proxy for the recovery of the capital portion of the debt incurred.

As is required by the MYPD methodology, the annual depreciation allowance is determined by dividing the cost of the asset by the estimated useful life of that asset. Table below reflects the revenue related to depreciation for the MYPD 6 period.

TABLE 23: DEPRECIATION

DEPRECIATION (R'millions)	Decision FY2024	Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Depreciated Replacement Costs (DRC)	57 628	55 208	53 348	50 991	50 162	48 835	47 301
Asset transferred to commercial operation post valuation date	12 634	18 192	12 951	18 143	26 348	30 061	37 929
Assets Purchases	455	462	1 702	1 974	2 176	2 101	2 042
Assets funded upfront by customers	(441)	(487)	(1 069)	(1 155)	(1 255)	(1 312)	(1 312)
Total Depreciation	**70 276**	**73 375**	**66 931**	**69 952**	**77 431**	**79 685**	**85 961**

9.5 Assets excluded from RAB

Depreciation for transmission and distribution assets as shown in table above, include assets that are funded via upfront capital contributions. In terms of the MYPD methodology these assets do not earn a return on assets and their depreciation is not included in the revenue requirement. The negative values reflected under "Assets funded upfront by customers" reduces the value of the RAB and depreciation.

The transfer to commercial operation (CO) includes the completed assets which have been funded upfront by customers. The objective of tracking these assets as a separate asset class is to ensure transparency; therefore, both the RAB and the depreciation are reduced accordingly.

9.6 Return on assets

The return on asset included in the MYPD 6 application is shown in the table below. Eskom is applying for 4%, 5% and 6% ROA for FY2026, FY2027 and FY2028 respectively.

TABLE 24: RETURN ON ASSETS

Return on Assets	Decision FY2024	Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Closing RAB (R'm)	1 027 136	949 554	1 183 895	1 201 861	1 236 628	1 249 527	1 307 026
Average RAB (R'm)	788 822	988 345	1 066 724	1 192 878	1 219 244	1 243 078	1 278 277
RoA Applied for %	1.70%	1.58%	4.00%	5.00%	6.00%	7.47%	9.69%
RoA Applied for (R'm)	13 410	15 616	42 669	59 644	73 155	92 908	123 916

The WACC, as determined by NERSA for the MYPD 5 period is used as a comparison for the cost reflective return on assets. It is likely that this value has increased since then. However, it allows for a conservative estimate, as Eskom migrates towards the cost reflective level.

The return on assets is being phased to allow for the smoothing of the tariff. This phasing allows the average price of electricity to migrate towards cost-reflective tariffs. In the absence of such a phasing, the price increase being requested will be significantly higher. Thus, Eskom is allowing for migration, to allow for consumers to experience a phased price increase. However, this migration is accompanied by risks which need to be managed. Should the risks materialise, a further burden is likely to be applied on the fiscus. The efficient costs do not go away and need to be funded. In essence the subsidy to all consumers continues to be provided for a longer period.

10 Capital Expenditure

The MYPD methodology allows for the capital related costs to be recovered over the life of the assets through return on assets and depreciation. Thus, it is clarified that capital expenditure is not included in the allowed revenue regulatory formula. The long-life capital nature of the electricity industry requires significant focus on build and replacement of assets for the functioning and reliability of the industry to provide the service of delivering electricity.

The capital expenditure required, over the MYPD 6 period, to meet reliable electricity supply into the future is per the table below.

TABLE 25: CAPITAL EXPENDITURE

Capital Expenditure (R'millions)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Generation	23 084	28 447	44 020	53 242	58 363	57 138	38 576	75 989
Transmission	3 542	4 663	9 154	20 063	36 987	39 046	49 347	43 027
Distribution	4 533	5 072	6 651	15 024	13 848	11 690	9 209	9 764
Total	31 159	38 182	59 825	88 329	109 198	107 875	97 132	128 780

10.1 Generation Capital Expenditure

In the application window, Generation related capital expenditure plans will focus on delivering the following projects:

- Generation new build programme - commercial operation of remaining unit of Kusile
- Generation technical plan and outage capital expenditure
- Clean energy projects
- Generation will invest in Cost-Plus mines which will provide Generation with a more sustainable source of coal. This is included as future fuel.
- Generation will also invest in projects to reduce particulate emissions and water consumption, on the journey towards environmental compliance.

10.2 NTCSA (Transmission) Capital Expenditure

Transmission’s network needs to be strengthened and expanded to connect new customers and generation to the network to enable country growth. In addition, investments for asset replacement are required for assets which have reached their end of life, in order to sustain a reliable supply of electricity. Transmission requires a significant increase for capital investment over the MYPD 6 period. It should be noted that there is an increase in the required investment compared to the previous MYPD control period, which can be attributed to accelerated transformer projects and synchronous condensers and new corridors required to integrate new generation.

Strengthening and capacity expansion includes new generation integration as well as strengthening projects which are required to ensure that the transmission network can evacuate and dispatch power from generation sources to the load centres and allow for future demand growth. It also includes projects for planned new customer connections as well as reliability projects relating to the Grid Code compliance requirements.

Environmental Impact Assessments (EIAs) are conducted in accordance with the National Environmental Management Act (NEMA) requirements for expansion and asset replacement projects. Land and servitudes are procured for substation and line construction projects based on valuations from independent and registered land valuators.

Asset replacement investments are required when assets have reached their end of life and can no longer be reliably operated. These investments are prioritized based on asset condition, network criticality and risk criteria.

Transmission plans the network according to the Grid Code and subject to funding and other resource constraints, builds the network in alignment with the Transmission Development Plan (TDP). Where insufficient funds are available for required network investments, a consistent set of rules is applied to prioritise projects and allocate funding in such a way that the maximum benefit is gained for customers.

10.3 Distribution Capital Expenditure

Distribution capital investments support the continued productive life of assets and the technical conditions necessary to maintain continued electricity supply to secure revenue streams and improve customer experience. The applied for capital expenditure is required to strengthen and refurbish the Distribution network to meet future growth requirements, whilst allowing the network to maintain current performance standards.

A key priority is to ensure a reliable and sustainable power supply. The Distribution Licensee will balance the need for resolving constrained networks whilst providing the supporting infrastructure for maintenance activities. Historically, the Distribution network performance gains are reflective of the investment choices made in the capital projects.

The Distribution network capital expenditure is employed in activities that are based on extensive planning that are implemented for the required network performance. A 10-year master plan informs the capital investment programme that supports the forecasted economic growth nodes. The capital investment programme supports the establishment of the required capacity to meet the future electricity demand with network performance at an acceptable level of reliability, maintainability and operability. The capital expenditure is also reflective of the execution capability within the Licensee, which is based on its own historical performance.

In compliance to the Grid code, a network development plan is formulated informed by the 10-year master plan for the immediate 3–5-year period.

The following factors are the key drivers for the capital expenditure:

- Enabling capacity as a precursor for growth in the economy and support to government-led initiatives.
- Further progressing towards regulatory and statutory requirements as per NERSA requirements which include NRS requirements.
- Ensuring commitment to a Distribution landscape that is focussed on universal access, IPP Integration and technological advancements, whilst maintaining current performance.
- The historical build-up is extensive and although continued investment is provided in this area, given the deterioration in the network's ageing profile and regression in the performance of the aged distribution networks, the requested investment may not fully suffice.
- Capital for strengthening and refurbishing existing Distribution networks and for new IPP projects.

10.4 Environmental Requirements

The environmental clause in the Bill of Rights sets the context for environmental protection, providing for an environment which is not harmful to health and well-being and for ecological sustainable development. The National Environmental Act and several Strategic Environmental Management Acts (SEMA's) give effect to the environmental right in the Constitution. The development of environmental legislation has resulted in new and more stringent requirements which Eskom is obligated to respond to in order to continue operating its power stations. Given the nature of Eskom's activities these requirements are far reaching, they affect all the licensees in some manner, including air quality, protection of the natural environment and biodiversity, water use and the impact on water resources, general and hazardous waste management, the utilisation of ash and licensing processes. These legislative requirements lead to operational and capital expenses which must be allowed to enable Eskom to retain its license to operate.

11 Primary Energy

11.1 Overall summary of primary energy

The next section will cover the primary energy (PE) and levies & taxes (L&T) components of the build blocks to the allowable revenue formula:

$$AR=(RAB \times WACC)+E+PE+D+R\&D+IDM \pm SQI+L\&T \pm RCA$$

Primary energy costs equate to the costing of the production plan (electricity supply required to meet demand). There are three sources of electricity supply comprising Eskom own generation (majority), domestic independent power producers (IPPs) and regional import of supply (international supply).

TABLE 26: DETAILED PRIMARY ENERGY COST

Primary energy costs (R'millions)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Coal usage	63 069	71 979	83 238	93 653	96 537	89 640	88 739	90 651
Water usage	2 332	2 573	3 368	3 936	3 988	4 359	4 812	5 194
Fuel and water procurement service	274	295	334	351	368	384	401	427
Coal handling	2 293	2 419	3 090	3 314	3 469	3 633	3 801	3 988
Water treatment	669	848	1 004	1 014	986	1 029	1 105	1 103
Sorbent usage	186	366	361	455	477	449	406	474
Sorbent handling	6	17	23	23	24	20	20	20
Gas and oil (coal fired start-up)	8 807	8 932	9 845	10 745	11 086	11 485	11 964	11 975
Total coal	**77 637**	**87 429**	**101 264**	**113 491**	**116 935**	**111 000**	**111 248**	**113 832**
Nuclear	674	649	840	982	1 519	1 648	1 951	2 231
Coal and gas (Gas-fired)	7	10	9	9	10	11	12	14
OCGT fuel cost	21 355	19 152	10 059	10 548	11 029	11 531	12 056	12 604
Ancillary services	357	370	1 929	2 970	3 568	4 679	4 224	5 438
Total primary energy	**100 030**	**107 611**	**114 100**	**128 000**	**133 061**	**128 869**	**129 492**	**134 119**
Environmental levy	7 033	6 829	6 861	6 539	6 279	5 337	4 781	4 767
Carbon tax	0	-	-	5 534	21 291	19 895	19 274	20 948
Independent Power Producers (IPPs)	43 534	57 662	56 236	66 633	77 640	109 820	135 510	140 943
International purchases (Dx)	12	12	13	13	13	14	15	15
International Purchases	6 459	8 036	12 007	10 249	9 724	13 642	11 838	12 371
TOTAL	**157 068**	**180 150**	**189 216**	**216 969**	**248 008**	**277 577**	**300 909**	**313 163**

The costs associated with most primary energy elements have remained relatively static from the projections for the MYPD 5 period to the MYPD 6 period. The total cost of coal burn from FY2026 to FY2027 increases, and then decreases for FY2028. In order for the system operator to meet the demand, the dependence on IPPs has diminished (compared to that originally envisaged by the Government Departments and the IRP). Thus, the additional dependence on Eskom's coal-fired power stations to fill this gap. It also results in securing more expensive coal to ensure continuity of supply. Due to a delay, the IPP costs increase in the latter years of the application. The IPP costs almost double in FY2028 when compared to the FY2025 projections. A significant change is due to the introduction of carbon tax. The carbon tax liability will become effective from 1 January 2026 and the full effect of over R20bn will be felt in the FY2027. The environmental levy contributions continue. The OCGT fuel costs increase due to diesel price increase. The load factor remains static at 6% for Eskom plants. The introduction of ancillary services from IPPs account for the increase in these costs. The ancillary services secured from Eskom Generation are costed as part of the generation operating costs and are not separated as an additional cost.

11.2 Independent Power Producers (IPPs)

The Government policy in accordance with the Integrated Resource Plan of 2019, was to significantly increase the contribution of energy sourced from IPPs. In addition to further acceleration energy from renewable sources, the risk mitigation plan for dispatchable energy as well as contribution from gas technology were envisaged to be introduced. As reflected in the production planning section of this document, it is evident that a significant amount of generating capacity that was to be commissioned did not materialise. In the period 2019 to 2023 – over 8 000MW of capacity was not made available to the system.

In accordance with the sections 3.1.4(e) of the GSFA, Eskom is required to seek approval from the DMRE, DPE and National Treasury with regards to the updated proposed IPP purchase costs and payment obligations to be included in the MYPD 6 application. Eskom has undertaken this process. Eskom has received feedback from all three relevant Government Departments, who all concur with the projections on IPP projects. The difference in energy to be secured from IPPs has dropped tremendously from what was originally envisaged by the Government Departments. This corresponds to shortfalls of approximately 26 TWh (FY26), 42 TWh (FY27) and 33 TWh (FY28). This is approximately 12% (FY26), 20% (FY27) and 15% (FY28) of the total energy supply that Eskom needs to accommodate.

TABLE 27: PROPOSED COSTS OF ENERGY FROM IPPS

IPP Costs (R millions)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Eskom short term programmes	**-**	**3 254**	**4 325**	**7 981**	**9 296**	**9 787**	**645**	**-**
MTPPP (Emergency Gen)	-	2 321	4 149	6 980	7 545	7 944	-	-
Short term (Standard Offer)	-	933	176	1 001	1 751	1 843	645	-
Load shedding reduction	-	-	-	-	-	-	-	-
Section 34 programmes (non RE)	**10 056**	**15 335**	**7 265**	**7 990**	**14 344**	**21 968**	**42 259**	**44 026**
DoE Peaking- Capital costs	2 063	2 101	2 148	2 174	2 201	2 236	2 260	2 291
DoE Peaking- Other costs	7 993	12 552	4 269	4 523	4 770	5 038	5 290	5 290
Risk Mitigation Programme	-	682	848	1 294	3 325	3 791	3 970	4 169
Gas programme	-	-	-	-	-	-	19 323	20 289
Baseload Coal	-	-	-	-	-	-	-	-
Storage	-	-	-	-	4 048	10 903	11 417	11 988
Renewable IPP	**33 479**	**38 872**	**44 325**	**50 322**	**53 639**	**77 682**	**92 200**	**96 487**
Renewable IPPs Round 1	11 422	12 841	13 817	14 455	15 144	15 889	16 532	17 375
Renewable IPPs Round 2	6 414	7 074	7 630	7 904	8 210	8 493	8 847	9 178
Renewable IPPs Round 3	7 114	8 283	9 271	9 718	10 168	10 662	11 139	11 665
Renewable IPPs Round 3.5	1 505	1 922	3 582	4 249	4 464	4 694	4 904	5 064
Renewable IPPs Round 4	3 747	4 534	4 945	5 185	5 437	5 713	5 977	6 267
Renewable IPPs Round 4+	3 276	4 218	4 454	4 667	4 890	5 135	5 369	5 626
Renewable IPPs Round 5	-	-	627	3 094	3 261	3 427	3 581	3 753
Renewable IPPs Round 6	-	-	-	1 050	2 018	2 110	2 194	2 287
Renewable IPPs Round 7	-	-	-	-	48	16 225	16 961	17 781
Renewable IPPs Round 8	-	-	-	-	-	5 335	16 696	17 492
Small-scale renewable - committed	-	-	-	-	-	-	-	-
Small-scale renewable - new	-	-	-	-	-	-	-	-
Solar Park Round 1	-	-	-	-	-	-	-	-
Total IPP energy costs	**43 534**	**57 460**	**55 915**	**66 293**	**77 279**	**109 437**	**135 104**	**140 513**
Network pass through	-	202	321	340	361	383	405	430
Total IPP costs	**43 534**	**57 662**	**56 236**	**66 633**	**77 640**	**109 820**	**135 510**	**140 943**

TABLE 28: IPP ENERGY PURCHASES (VOLUMES)

IPPs - GWh	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Eskom short term programmes	**-**	**1 849**	**1 605**	**3 215**	**3 898**	**3 909**	**527**	**-**
MTPPP (Emergency Gen)	-	889	1 430	2 269	2 321	2 328	-	-
Short term (Standard Offer)	-	960	175	946	1 577	1 581	527	-
Load shedding reduction	-	-	-	-	-	-	-	-
Section 34 programmes (non RE)	**1 098**	**2 374**	**1 382**	**1 770**	**3 445**	**3 514**	**10 513**	**10 513**
DoE Peaking	1 098	2 104	528	528	528	530	528	528
Risk Mitigation Programme	-	270	854	1 241	3 039	3 300	3 291	3 291
Gas programme	-	-	-	-	-	-	7 008	7 008
Baseload Coal	-	-	-	-	-	-	-	-
Storage	-	-	-	-	-123	-316	-315	-315
Renewable IPP	**16 859**	**18 748**	**20 868**	**26 380**	**27 872**	**49 836**	**60 571**	**60 439**
Renewable IPPs Round 1	3 398	3 683	3 763	3 753	3 747	3 748	3 721	3 723
Renewable IPPs Round 2	2 790	2 959	3 055	3 047	3 043	3 036	3 031	3 024
Renewable IPPs Round 3	4 011	4 290	4 619	4 617	4 612	4 618	4 603	4 600
Renewable IPPs Round 3.5	300	362	761	855	854	856	853	848
Renewable IPPs Round 4	3 490	3 952	4 068	4 063	4 058	4 062	4 048	4 043
Renewable IPPs Round 4+	2 869	3 502	3 504	3 498	3 491	3 493	3 479	3 472
Renewable IPPs Round 5	-	-	1 099	4 770	4 784	4 788	4 765	4 755
Renewable IPPs Round 6	-	-	-	1 776	3 229	3 215	3 183	3 160
Renewable IPPs Round 7	-	-	-	-	54	16 457	16 380	16 349
Renewable IPPs Round 8	-	-	-	-	-	5 563	16 508	16 465
Small-scale renewable - committed	-	-	-	-	-	-	-	-
Small-scale renewable - new	-	-	-	-	-	-	-	-
Solar Park Round 1	-	-	-	-	-	-	-	-
Total IPP	**17 957**	**22 972**	**23 856**	**31 364**	**35 214**	**57 259**	**71 610**	**70 952**

11.3 Section 34 Energy Procurement

Section 34 IPP programme refers to the government initiative aimed at diversifying the country's energy mix and increasing the contribution of renewable energy sources to the national grid. The ERA (S 34) empowers the relevant Minister to procure new generation capacity from IPPs which involves a competitive bidding process, where IPPs compete to secure contracts to develop and operate energy projects.

11.3.1 Renewable Energy IPP Programme

All prices are indexed to the assumed inflation of 6%, except for certain bid windows (BW 2 and BW 3 are only partially indexed). Bid Windows 1 to 4 are included as per the energy expectations in the power purchase agreement (PPA) and prices as per PPA. The expected commercial operation dates for projects under Bid Windows 5 to 8 have been provided through the GSFA process. Of the original 25 preferred bidders in Bid Window 5, only 12 reached financial close with a total 1 234 MW. These projects are expected to be commercially operational between September 2024 and June 2025. Under Bid Window 6 six photo-voltaic (PV) projects with a total 1000 MW of capacity were announced as preferred bidders. These projects are expected to enter commercial operation between March 2026 and May 2026. Bid Window 7 is expected to result in 3 200 MW of wind capacity and 1 800 MW of PV (commercial operation in February 2027). Bid Window 8 is expected to result in the same levels of capacity for wind and PV generation with commercial operation in October 2028.

11.3.2 Peaker programme

The two IPP peaker power stations are commercially operating and assumed to be operating at 6% load factor as well as a projected costs split between the “fixed” capital component and variable energy component.

11.3.3 Risk Mitigation Power Purchase Programme (RMPPP)

The RMPPP is expected to realise 578 MW of the original 2000 MW awarded capacity, with expected commissioning (following the current 150 MW in operation) between August 2025 and February 2026. The expected load factor is 50% for the full capacity and an expected cost of R2.17/kWh in 2020 rands, escalating at CPI.

11.3.4 Gas programme

The 2000 MW gas capacity procured under a specific gas programme is expected to be commercially operational by April 2028 at a load factor of 40% and cost of R2.14/kWh.

11.3.5 Section 34 - Storage

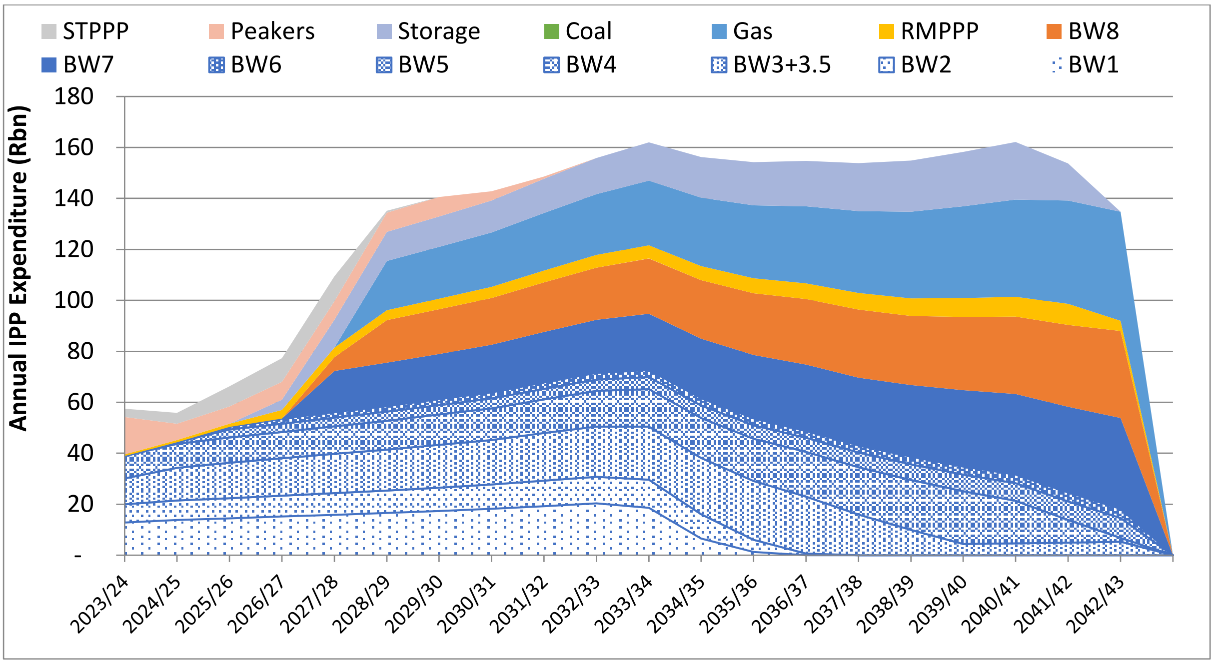
The IRP provides for 513 MW of battery storage. It is expected this will operate from June 2026 with 4 hours storage capability, 89% cycle efficiency and one cycle per day for the duration of the contract. This means that each day will see 4.5 hours of charging and 4 hours of generation, thus daily net consumption is 256 MWh, and annual net consumption is 93 GWh. The energy payment to the storage facility is expected to set to counterbalance the energy charge (e.g. a fixed charge of 30c/kWh for 4.5 hours of charging is offset by a payment of 33.7c/kWh for 4 hours of output). Thus, the costs reflected are for the fixed costs of the generator (annualised capacity costs and fixed operating and maintenance).

Additional storage capacity has been sought under Bid Window 2 (615 MW) and Bid Window 3 (616 MW). The additional capacity is expected in November 2026 for Bid Window 2 and April 2027 for Bid Window 3.

11.4 Eskom short-term programmes

Eskom has signed two contracts under the Emergency Generation Programme (160 MW) with the potential for another 440 MW between September 2024 and June 2025. The Standard Offer has also received applications (totaling 1 165 MW) with 620 MW signed. The signed capacity is expected between August 2024 and January 2026.

FIGURE 17: SUMMARY OF IPP COSTS OVER LIFE OF CONTRACTS



The figure above reflects the nominal cost of IPP contracts over the life of the contracts for each of the bid windows from Bid window 1 to Bid Window 8, as well as the non-renewable Section 34 programmes (Gas, Risk Mitigation, Coal and Storage) and Eskom programmes. All of the contracts have annual increases included in the contracts.

11.5 International Purchases

Electricity imports from neighbouring countries is mainly driven by supply from Cahorra Bassa (HCB). This source has been and will continue to be subject to fluctuations due to network constraints, drought conditions affecting the level of the dam and availability of HCB's 5th generator on a non-firm basis.

TABLE 29: INTERNATIONAL PURCHASES

International Purchases	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
International purchases (R'm)	6 459	8 036	12 007	10 249	9 724	13 642	11 838	12 371

11.6 Eskom own primary energy market overview

11.6.1 Overview of the Coal Business Environment

FIGURE 18 : COAL VALUE CHAIN

Within each of these functional areas lies an array of factors, over which Eskom has varying degrees of influence. Eskom is exposed to various factors that have had and will continue to have implications for costs and security of primary energy supply to Eskom. Some of these factors are discussed below.

11.6.2 Impact of economic uncertainty on the long-term growth trend

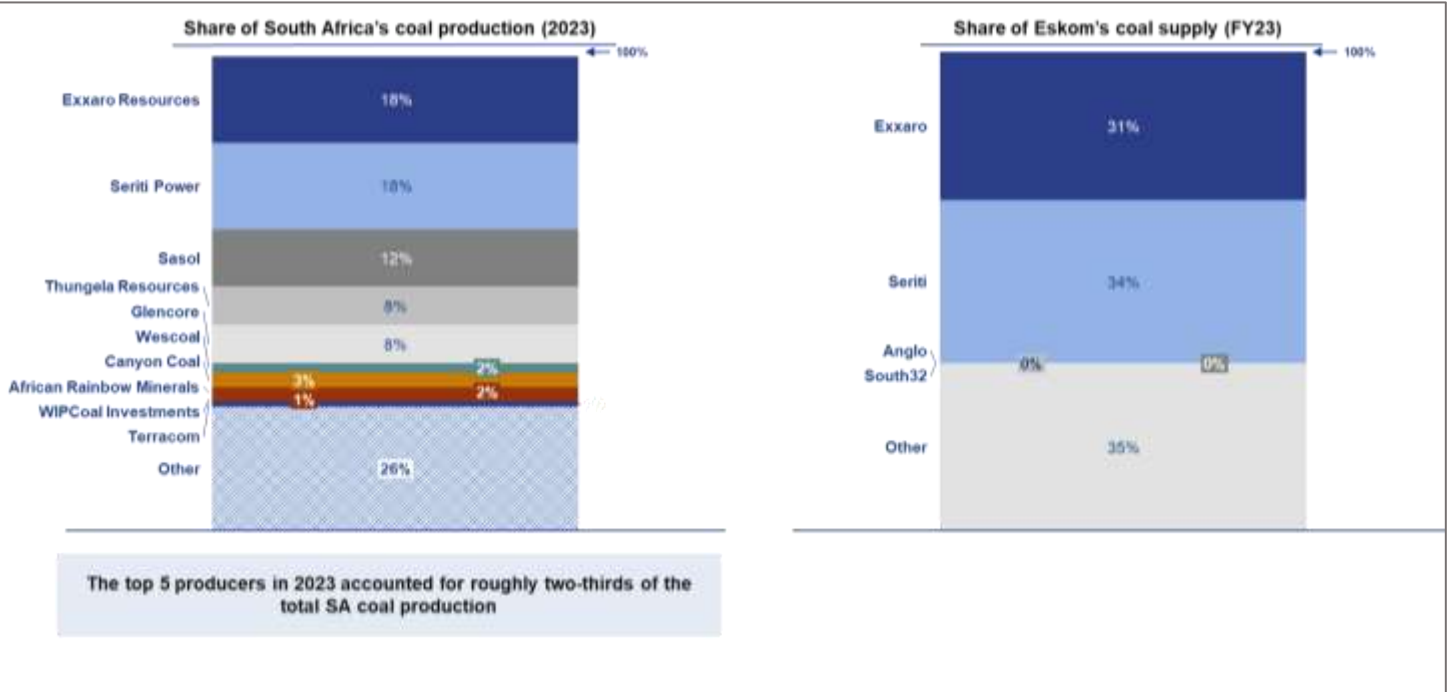
Eskom's coal supply strategy is impacted by the electricity demand forecast. This, in turn, is based on the forecast for economic growth in South Africa. After the high growth and consequent high electricity demand of 2003 – 2008, the subsequent global economic meltdown resulted in a sharp decline in electricity demand. Recent forecasts are that South Africa will experience very little economic growth. This is reflected in the flat coal purchases volumes forecast for the MYPD 6 period. Eskom can base its electricity, and coal, demand forecast on this scenario, but continued economic uncertainty will impact on the accuracy of electricity demand forecasts, reduce the accuracy of forecasts, and increase the risk of under- or over-supply of primary energy.

Continued uncertainty and economic instability increases the risk of over or under contracting of coal supply, which necessitates the requirement for Eskom to increase the volume flexibility in the portfolio of coal contracts. However, this flexibility will bear a cost. Continued uncertainty will also increase the risk associated with cost projections as many of the coal supply agreements are linked to external indices or cost drivers.

11.6.3 Changing the coal industry structure

Perhaps, because of both the economic and political environment, where South Africa previously saw the emergence of more junior and BEE miners in the coal sector, the current cyclical downturn has resulted in a dearth of new mines. The previously hopeful new players provided Eskom with a larger supplier base. The figure below illustrates that approximately 64% of the South African coal market is dominated by five suppliers.

FIGURE 19: PRIMARY COAL PRODUCERS AND ESKOM SUPPLIERS



Source: Wood Mackenzie, Eskom

With the exit of Anglo Coal and South32, there has been further consolidation of market share, and consequently, further consolidation of Eskom's coal supplier base. Seriti and Exxaro supply more than 60% of Eskom's coal.

Implications of the changing industry structure include:

- Funding is a major challenge especially for smaller miners
- Lack of large-scale investment into the coal mining industry which will likely create a supply shortage in the future
- Slowdown in global and local economic growth, and the resultant decrease in export demand and pricing, increases the risk of marginal mines facing liquidity challenges. This increases Eskom's supply risk
- Increase in export demand for a Richards Bay (RB) 3 product (lower export specification product) has removed the availability of the Eskom quality middlings coal product that was previously available to Eskom

11.6.4 Mines have an alternative market

Existing mines are taking advantage of the high export coal prices. Many investment decisions which were made at the height of the last commodity boom are now online.

However, these mines are targeting the more lucrative export market and not the domestic market. The relatively weak exchange rate also provides an incentive to earn revenue from exports. Facilitating these exports, and reducing the coal available to Eskom, are traders with export allocations at the Richards Bay Coal Terminal (RBCT). These traders are willing and able to buy up coal from small miners, paying cash on delivery.

Although China tried to reduce thermal coal's share of the generation mix in order to raise environmental standards in the country, the lack of alternative power and heating supplies are expected to result in this policy being relaxed in the colder months. If the country does not increase its coal production, it will have to import coal. While India is expected to become self-sufficient in producing its own coal, the country is still reporting a shortage.

Major companies have stated that there will be no further greenfield investments in new coal mines. Eskom will therefore have to contend with a reduced supply, from reduced investments, as well as displaced export coal, which will likely impact prices.

The demand for lower quality coal is reflected in the fact that the bulk of coal exported out of Richard's Bay is now the 5 500 kcal coal instead of 6 000 kcal, and that coal of 4 800 kcal is also being exported. These are qualities used by Eskom's power stations.

Implications:

- Uncertainty makes planning for coal purchases very challenging. There could be significant variations between plans and actual events and costs.
- Because of the uncertainty, there is a lag in new projects.
- Coal allocated for Eskom is being diverted to the export market.
- Suppliers are demanding higher base prices when negotiating new contracts.
- Proliferation of other markets for coal that used to be exclusively for Eskom's use. Historically, export prices cross-subsidised Eskom's middling product. Now the middling product is being exported to India.

11.6.5 Deteriorating resource/reserve base

The mines in the Mpumalanga basin are either in or are entering a phase where the cost of coal is driven upwards by factors such as deteriorating coal quality, increased occurrence of geological disturbances, thinner coal seams, depleting reserves in the currently accessible reserve blocks, high investments to access the remaining new small reserve blocks and longer 'on-mine' transport distances. These factors increase coal handling, maintenance and labour costs and reduce productivity, while increasing the need for costly beneficiation of the coal. The majority of Eskom's current long term coal supply sources have been in operation in excess of 20 years and, as some of the oldest operating mines in South Africa, are directly impacted by these increased costs. Managing the quality and quantity of Eskom's coal supply is becoming more challenging.

Implications:

- Costs of establishing and operating new mines will be significantly higher than in the past, due to more geological complexity, thinner and deeper coal seams. These factors will likely translate into higher coal prices for Eskom.
- Substantial investment will be required to open new, more marginal coal reserve blocks (with limited life as the large blocks have been mined) to maintain coal supplies.
- Calorific value of coal is reducing. Increased need for beneficiation of certain resources to meet power station coal quality parameters, further increasing costs.

11.6.6 Increased transport distances between mines and power stations

The procurement of coal from sources, which are greater distances away from the power stations adds to the complexity.

Implications:

- Likely to incur additional logistics cost to deliver coal to the Power Station which will result in an increase in the coal cost.
- Logistics strategy must consider the interests of transporters, those of Eskom and the public regarding cost and road safety.

11.6.7 Increasing environmental pressure

Eskom's coal-focused generation mix requires significant volumes of water, a scarce and important resource in South Africa. The opening of new coal mines to supply both Eskom and the export market is expected to place pressure on the already strained environment and on water catchments. Existing and new environmental legislation is expected to be more stringent than past standards, and the requirements are likely to result in a decrease in productivity levels and/or an increase in costs.

Implications:

- New emissions standards for power stations will necessitate higher coal quality specifications, which could, potentially, increase the cost of coal.

- Similarly, any more stringent environmental legislation will increase the mine environmental, rehabilitation and closure costs, leading to higher overall prices charged to Eskom.

11.6.8 Constraints on water supplies

Eskom is a strategic user of water, consuming approximately 2% of the total annual use of the country, which is equivalent to the consumption of the City of Cape Town. As power stations are decommissioned, Eskom's demand for water declines. However, total country water demand may increase as the South African economy grows.

Implications:

- Increased demand will require significant investment in new water schemes, the cost of which must ultimately be recovered from both current and future users, including Eskom.
- There is a need for significant investment in infrastructure to supply water to the Waterberg area, which will increase water costs and tariffs in that region.
- There is a possibility that the Department of Water and Sanitation (DWS) might re-price the water tariffs to reflect water scarcity in the country.
- The DWS can include more water tariff components to fund infrastructure, administration and initiatives through the revision of the National Water Pricing Strategy
- As water quality from some sources declines, power stations may need to switch the source of water, which may result in additional costs. Alternatively, power stations may incur higher water treatment costs.

11.6.9 Supply constraints in key mining inputs

As geo-political stability in many regions remain uncertain, commodity prices and supply also fluctuate. This volatility is compounded by labour unrest in the mining industry in South Africa and community protests that could result in mine closures and/or higher prices of commodities. While the price of coal from Eskom's existing contracts is not impacted significantly by export prices, potential increased exports of RB3 type coal does affect the coal that is available for Eskom in the South African market.

Implications:

- Continued real increases in domestic mining input and labour costs will impact all of Eskom's coal contracts as industry wide input cost changes are ultimately passed through to Eskom, since they are deemed to be beyond the control of the coal suppliers.

- Lower volumes of RB3 (Eskom quality) coal available to Eskom in the South African market.

11.7 Key Assumptions underlying the coal sourcing plans and cost forecasts

Key assumptions underlying the coal sourcing plans and cost forecasts are detailed below:

11.7.1 Coal sources and volumes

- Dedicated (Cost Plus) mines, produce at expected levels, which are largely below contractual volumes.
- Multi-product (Fixed Price) mines produce at expected levels.
- The Matla Coal Supply Agreement will be extended.
- Capex will be available as and when required for investment in cost plus mines.
- Any shortfalls will be sourced from smaller operating mines, most of which are already supplying Eskom.

11.7.2 Coal costs and price escalations

- An adjustment of 7% p.a. was assumed for the Cost-Plus mines costs. However, the rand/ton cost increase is impacted by both the inflation adjustment and the change in the volume of saleable tons produced.
- Fixed Price mine costs have been escalated in accordance with the terms of the contracts. The average annual increase for this contract type is 10%.
- A modelled index has been used for future escalations for contracts that are still to be negotiated. The average annual increase for this contract type is 7%.
- Prices for medium term contracts have been based on existing contractual delivered cost. The average annual increase for this contract type is 7%.

11.7.3 Water

- The new power stations (Medupi and Kusile) will use flue gas desulphurisation (FGD) at 0.45 litres per units sent out (l/USO). FGD at Medupi will only come after FY2029 when the Mokolo Crocodile Water Augmentation Project (MCWAP)2 project will start to deliver water into the Mokolo catchment.
- Several new infrastructure projects are planned to meet the water requirements of Eskom and other large water users. All new infrastructure will be developed and financed by the DWS. The costs will be recovered through the water tariffs. Any under recoveries

due to the actual water demand being below the projected demand during the project feasibility stage will be recovered in the following year.

- Current infrastructure is old. The DWS has a backlog of maintenance, which will also result in an increase to the water tariff.
- Tariffs for Medupi and Matimba comprise of MCWAP1 until FY2029. MCWAP1 tariffs are calculated on a take or pay basis.
- The plan is based on normal rainfall and does not include drought mitigation plans.

11.7.4 Logistics

- Coal to Grootvlei and Majuba, with access to sidings, is planned on rail.
- All short- and medium-term contracts are on a Delivered basis.

11.8 Key drivers affecting increase in coal cost forecast

11.8.1 Uncertain energy plans

IPPs constitute an increasing proportion of total generation in the MYPD 6 production plan but have historically underperformed. The production plan, in turn, impacts the coal procurement requirements. Deviations from the assumptions made regarding IPPs will impact on Eskom in terms of additional generation and additional coal needing to be procured. Changes in the production plan can result in significant changes in coal procurement and burn cost.

11.8.2 Logistics

Transport costs depend on the distances over which coal is transported, the transport mode and the transport rate. The coal export market impacts the availability of trucks and the cost of road transport. The negative impact on Eskom's cost is exacerbated by the cost of fuel and the unavailability of trains to move coal.

11.8.3 Cost plus mine production

As mines age, lower production levels have resulted in a higher unit cost at the respective mines. The impact of limited historical capex investments continues to compound production challenges and increase costs. These contracts remain more beneficial to Eskom than an alternate supply as they have a transport advantage over any other supply.

11.8.4 Mining costs

- The input costs into coal mining are increasing at rates higher than inflation.
- The natural geology in more difficult parts of the mine is also contributing to increasing coal mining costs.

11.8.5 Water

- The DWS underspent on maintenance and refurbishment on bulk water infrastructure over the years. This has resulted in a backlog of maintenance and refurbishment that is required to be planned and implemented in the forthcoming years to ensure plant reliability and availability.
- The development and implementation of new water infrastructure, such as the MCWAP2 required for water to the Waterberg, will increase the cost of water.
- Water costs are regulated in line with the prevailing National Water Pricing Strategy. The new draft Water Pricing Strategy has yet to be finalised and could result in water tariffs changing. Water cost increases are primarily driven by increasing water demands of the new build, which require new water infrastructure and therefore higher capital tariffs to repay the financing debt.
- Delayed implementation of the Waste Discharge Charge in the forthcoming years will increase the cost of water. This has not been provided for due to the uncertainty regarding the timing of implementation.

11.8.6 Sorbent

- The coal-fired power stations where FGD is planned are geographically remote from viable sorbent sources; hence logistics and the final delivered cost will contribute to the selection of the most cost-effective option.
- Estimated pricing escalations are assumed to be driven by producer price index (PPI).
- Greenfield sources will require capital investment in rail infrastructure and as such will require a return. However, Eskom is looking for other sources of sorbent to reduce dependence on a single source.

11.8.7 Stricter Environmental Legislation

- More stringent mine closure and rehabilitation requirements.
- More stringent legislation regarding water management and disposal.
- More stringent legislation regarding air quality and emissions.

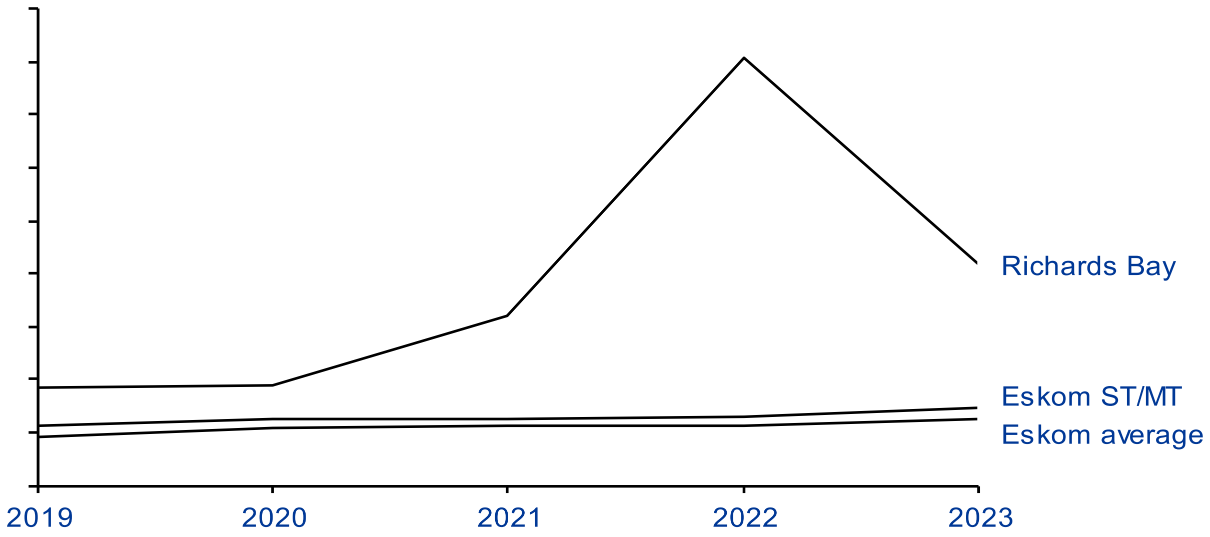
11.9 Key opportunities and challenges

- The South African coal market still requires substantial investment and recapitalisation to meet both domestic and export coal requirements. More suppliers are needed to improve the competitiveness and responses to requests for proposals for coal. The current economic environment is not conducive to investment.
- Eskom's financial position and the limitations on borrowings create a difficult environment for Eskom to raise capital for further investment in maintaining existing cost-plus coal mining operations.
- Funding within the coal environment remains a substantial challenge for new and established miners, as lenders look for opportunities in the clean energy space.

11.10 Benchmarking

This section compares the volumes and prices of coal supplied to the domestic market (primarily Eskom) with that exported. The graph below reflects the trend in the average Eskom price per tonne compared with the price out of Richards Bay (converted at the average ZAR/$ for the year). The purpose of the graph is to indicate that the average export prices far exceed the average prices Eskom pays. This gap is expected to remain as a result of higher US$ export prices and the weakening in the ZAR/$ exchange rate. This provides suppliers with leverage during price negotiations. It also provides an incentive for mines that export and supply to Eskom to prioritise exports at the expense of Eskom.

FIGURE 20: AVERAGE STEAM COAL PRICES(R/T)



Sources:
Richards Bay price: HIS. 5 700 kc discounted to 5 300 kc
Eskom PED

The difference between the Eskom average price and that of the Eskom short term/medium term (ST/MT) price is indicative of the difference between prices from the long-term cost plus and fixed price contracts, and prices from the ST/MT contracts. This also makes a case for further investment in the cost plus mines.

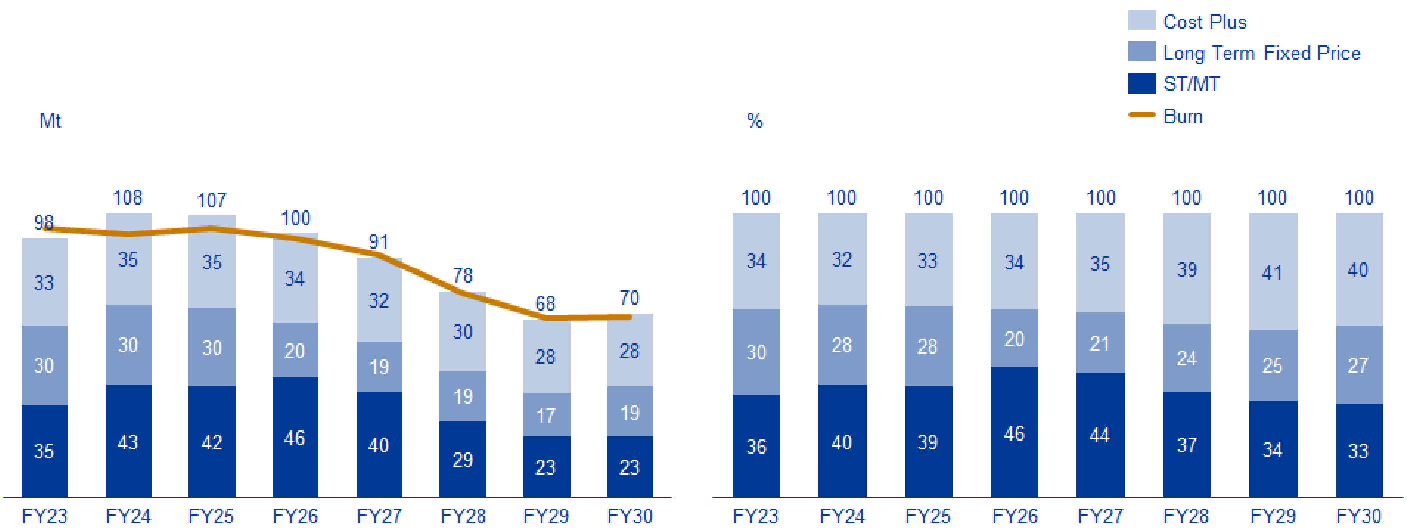
11.11 Coal Supply to meet Coal Burn requirements

11.11.1 Coal Volumes

The volume of coal to be purchased is a function of the opening stock, the coal forecast to be burnt and the closing stock required as per Eskom's coal stock policy. The coal to be burnt is determined from the generation production plan, in which power stations are scheduled according to cost, fuel availability and maintenance plans. These volumes are determined for each power station. While gross electricity generation remains relatively steady, Eskom's share of total electricity generation declines over this period.

The figure below reflects the volume of coal forecast to be procured over the FY2025 – FY2030 period. The proportion of coal from the cost-plus mines assumes that Eskom will extend the cost-plus contracts and invest in the cost-plus mines.

FIGURE 21: COAL PURCHASES VOLUMES



- Volumes from ST/MT sources decrease as total purchases decrease because of decreasing burn
- ST/MT includes contracted and uncontracted coal

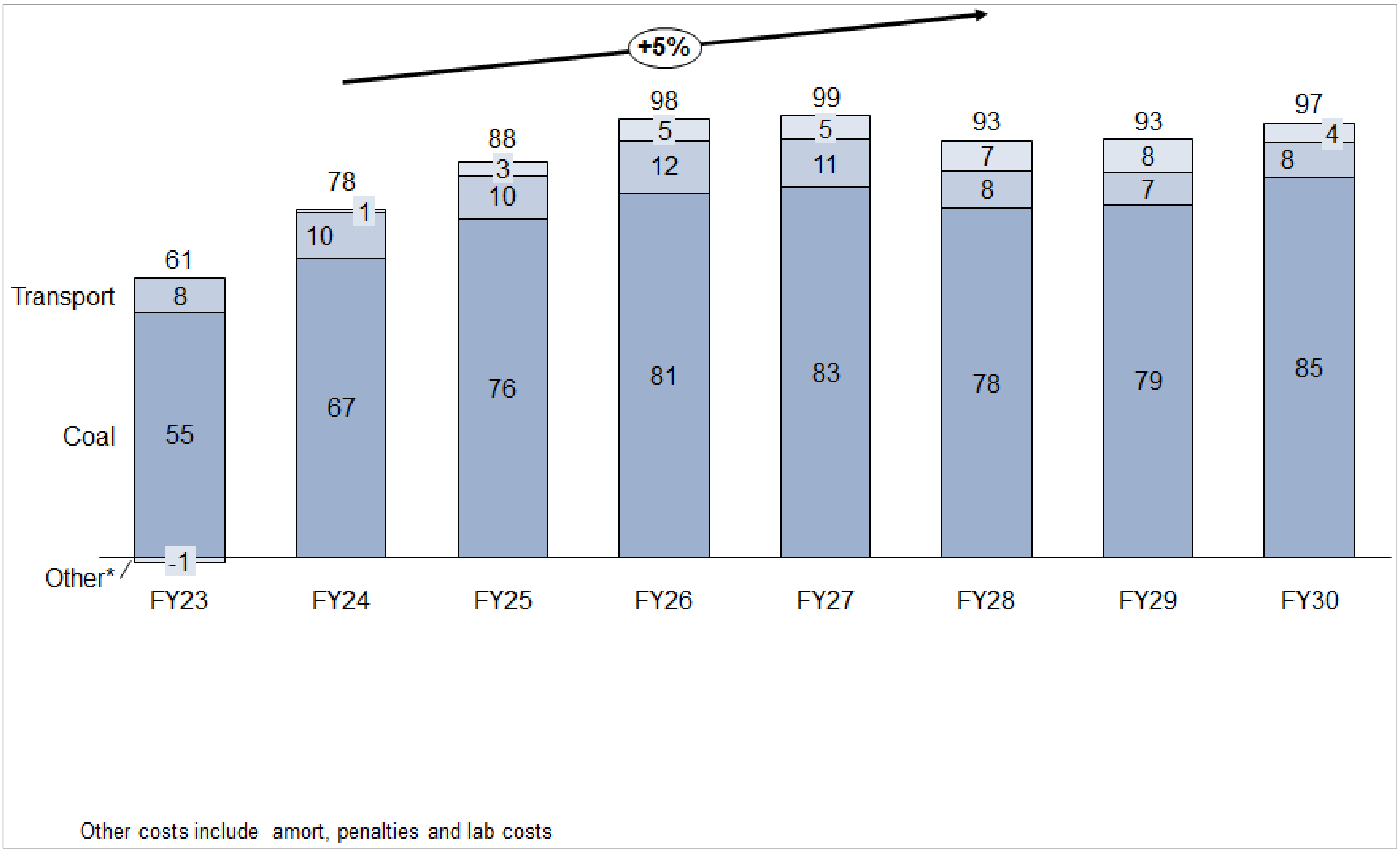
As the coal required for burn decreases and production from the cost-plus mines reduces, coal that is required from the ST/MT market increases slightly in FY2026 and then also reduces. The rate at which production from cost plus mines decreases is dependent on capex funding for the cost-plus mines being available when required. The benefits of investing in the cost-plus mines are:

- Coal from a source very close to the power station does not incur additional transport costs.
- Fixed costs at the mines are high, so increased production reduces the unit cost of coal.
- Fewer trucks transporting coal reduces wear and tear on the roads and reduces the likelihood of road accidents involving the trucks.

11.11.2 Coal Purchases Costs

Eskom's forecasted spend on coal over the three years, FY2026 – FY2028, is R289 bn. The total cost of coal purchased from FY2026 – FY2028 increases by an annual average of 5% during the MYPD 6 period. The unit cost (R/t) increases by an average annual rate of 10% over the FY2026 – FY2028 period.

FIGURE 22: COAL PURCHASES COSTS (R'BN)

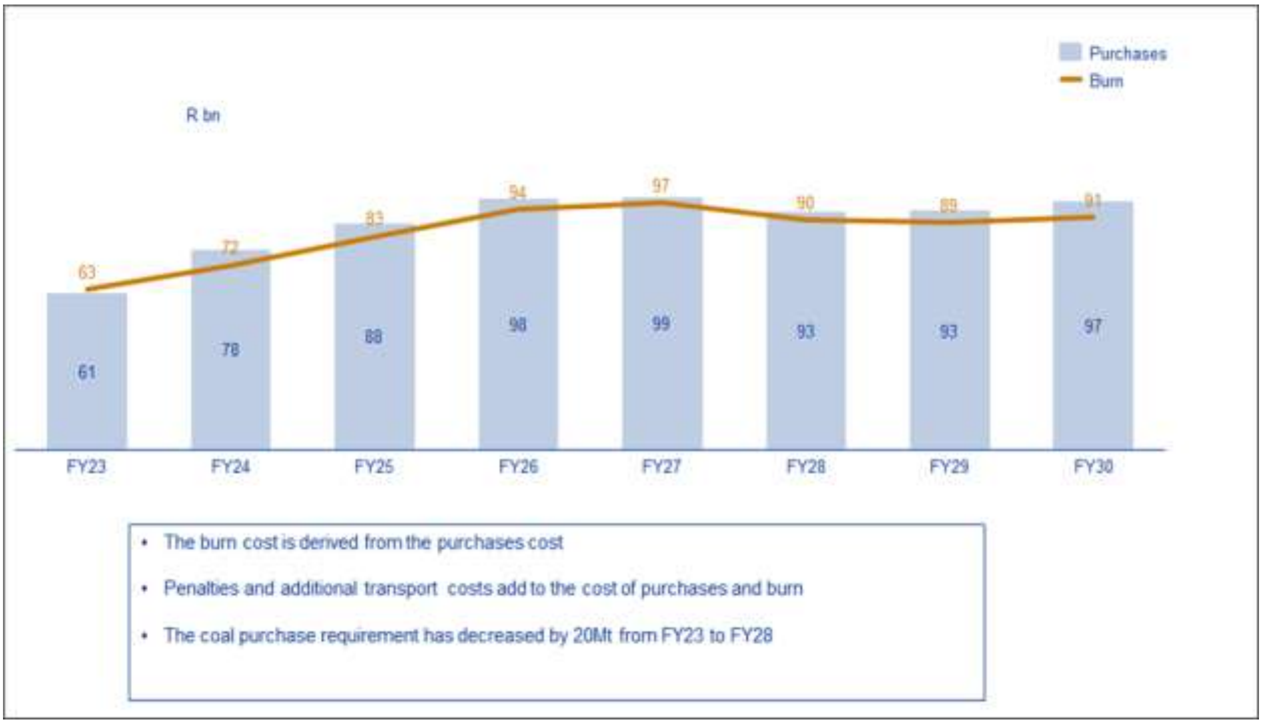


While some coal has been moved from Medupi Power Station to other power stations to reduce the take or pay penalty at Medupi, there is still excess coal at some stations, mostly at Kusile, which cannot be burnt elsewhere because the qualities are incompatible. Take or pay penalties have been estimated for this. Transport costs have been included for the coal to be moved from Medupi to stations in Mpumalanga.

11.11.3 Coal Burn Costs

Coal burn costs increase from FY2023 (R63 bn) to FY2028 (R90 bn).

FIGURE 23: COAL BURN PROJECTIONS (R'BN)



11.12 Water usage costs

Eskom pays for the water it consumes through a series of water tariffs. These are legislated, so Eskom has no control over the tariffs. Historically, water costs have been very low as a percentage of the Eskom operating costs. The main reason for this is that the water infrastructure assets were constructed several years ago and are almost completely depreciated. As the demand for water has increased, new infrastructure and water charges have been introduced and the cost have increased. Furthermore, the cost increases as the distances over which water needs to be transferred increase and as new tariffs are introduced into legislation.

New water infrastructure includes augmentation to the Vaal, Komati and Mokolo water schemes. The DWS National Water Pricing Strategy allows DWS to implement these projects "off budget" and to recover associated costs via a tariff. The Komati and Mokolo costs are recovered on a take or pay pricing basis.

The water financial plan comprises the following cost elements:

- Water cost, including cost of new water infrastructure.
- Electricity.

- Operations and maintenance.
- Amortisation and capital expenditure.

11.13 Sorbent

Sorbent (limestone) is required for the flue gas desulphurisation (FGD) technology at Kusile Power Station. The retrofit of FGD technology at Medupi Power Station has been delayed. The sources identified for this sorbent are located in the Northern Cape. The limestone is railed from the Northern Cape to Mpumalanga. Then, because of a lack of rail infrastructure, it is trucked to the power station. This process increases the delivered cost of sorbent significantly. The use of sorbent also increases the water requirements at power stations. The primary energy water volumes and cost include water for FGD at Kusile, based on a requirement of 0.45 litres per unit of energy sent out.

11.14 Nuclear fuel

Nuclear Fuel procurement comprises the acquisition of uranium, conversion, enrichment and the fabrication of the fuel assemblies for Nuclear Fuel. Nuclear fuel costs mainly comprise four categories, being Uranium, Uranium Conversion, Uranium Enrichment and Fuel Assembly manufacturing. The cost contribution per category depends on market prices and the ruling exchange rates.

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. Nuclear fuel prices show an increasing trend, which has been evident for the last few years due to geo-political events as well as the drive to low-carbon energy solutions. Eskom Generation has contracts in place that covers 100% of Koeberg's demand until 2026 for fuel assembly fabrication, a contract for the procurement of uranium until 2028, a contract for conversion and enrichment services for 80% of Koeberg demand until 2028 and enriched uranium panel contracts for 20% of Koeberg demand until 2028.

The pricing formula for the fuel fabrication is 100% a base escalated price. For the rest - the uranium, uranium conversion and uranium enrichment, a mix of price conditions have been agreed to. The mix considered are between base escalated and market related prices, a mix between term and spot market prices and/or a reset of the base price to market during the contract period. Prices are stated in the international functional currency of USD and are translated into ZAR. All the nuclear fuel expenditure is incurred in foreign currency and cashflow hedge accounting is applied to the purchases. The cashflow hedge accounting requires a basis adjustment to the price of the delivered fuel. Fuel procurement volumes will fluctuate as they follow the delivery requirements for Koeberg's production plan. Fuel is required to be delivered approximately six months prior to each refuelling outage. The fuel manufacturing process is approximately eighteen months with contractual progress payments throughout the fuel manufacturing cycle. This results in the above purchasing cashflows being different from the fuel burn expenditure in Primary Energy in the Income Statement.

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 approximately 54 months. Thus, there is not a direct correlation between when the nuclear fuel procurement costs incurred and when it is expensed as primary energy costs.

11.15 Open Cycle GasTurbines (OCGTs)

The load factor for Eskom's OCGTs during the forecasting period was assumed to be 6% which translates to 1266 GWh per annum. This is based on the assumptions made when developing the production plan. Should the reality turn out to be different from the assumptions, then the OCGT usage could be higher than that assumed. The only possible mitigations against OCGT usage higher than the assumptions are increased dispatchable capacity (from either Generation of other generators) and improving the reliability and predictability of the Generation fleet. The fuel used is mainly diesel (Ankerlig and Gourikwa). The price of the diesel is subject to the international USD price of Brent crude oil and the ZAR/USD exchange rate.

TABLE 30: ESKOM OCGT USAGE

Open Cycle Gas Turbines (OCGTs)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Volumes - GWh	3 018	2 539	1 266	1 266	1 266	1 266	1 266	1 266
OCGTs costs- R'm	21 355	19 152	10 059	10 548	11 029	11 531	12 056	12 604
Load Factor	14%	12%	6%	6%	6%	6%	6%	6%

When making a decision to run the OCGTs, all available resources are considered, for the current day as well as the next few days. Possible restrictions on Eskom generation include the dam levels at the pump storage stations (Ingula, Palmiet and Drakensberg) and the availability of water at the other hydro stations (Gariep and Vanderkloof) which is managed by the DWS. Once available base-, mid merit and hydro-generation has been utilised or planned to be utilised over peak, load reduction demand response options are dispatched. These have limited energy reduction opportunity and they are normally planned to be utilised over peak. Emergency reserves are then considered. These include Emergency Level 1, Interruptible Load Shedding (ILS) and the OCGT generation.

11.16 Start-up fuel and oil

Fuel oil is used to assist in stabilising combustion within coal-fired boilers, typically during transient conditions, and may be required due to sudden load changes, plant defects or out-of-specification coal properties. The most significant fuel oil consumption rate is during a cold start-up of a unit when a unit has been off for more than 36 hours. Start-ups occur after planned and unplanned outages and trips. The increased fuel oil usage is caused by a combination of factors such as ageing equipment, spares obsolescence and unexpected plant breakdowns and other operating conditions which requires the teams for normal planned maintenance to be re-assigned to clear plant breakdowns and production losses. Further, in the current environment of the generating units' performance being unpredictable, the use of fuel oil for combustion support assists in keeping a unit running (continue providing energy to the system), thereby circumventing increased loadshedding.

11.17 Water treatment

The quality of water from the various sources also impacts on the water treatment cost. The water treatment costs increase over the period.

11.18 Coal Handling

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. This includes stockpile maintenance, and coal reclamation. It is an integral part of power production, and the costs reflect a moderate increase over the planning period.

11.19 Environmental levy

The environmental levy on the generation of electricity from non-Renewable generators was promulgated in July 2009. All Eskom generators, with the exclusion of Hydro and Pumped Storage Power Stations, were registered and licenced as manufacturing warehouses as required by the legislation.

From 1 July 2012, the environmental rate is 3.5c/kWh. The actual payments to SARS are determined by the true metered generated volumes. The production plan which measures energy sent out as measured after the high voltage transformer is used to derive the assumed cost. To obtain the generated volume an expected auxiliary consumption, based on actual historical performance, which is unique to each power station is added to the energy sent out volume as published in the production plan. This derived generated volume is then charged at the applicable environmental levy rate for that period to obtain the forecasted cost per power station. It is assumed for the planning period that no further rate increases will occur. However, it needs to be noted that the carbon tax liability will be introduced during the MYPD 6 period. Thus, carbon tax is an addition to the environmental levy that is recovered from consumers. The methodology, as approved by NERSA is based on the principle that the levy is raised at electricity production and that the electricity sales volumes is lower than the production volume. Thus, the environmental levy cost is equivalent to the revenue related to the environmental levy.

11.20 Carbon tax

11.20.1 Activities subject to the tax

The carbon tax has been introduced by National Treasury, in addition to the existing environmental levy on the generation of electricity from non-renewable resources. The Carbon Tax Act came into effect from 1 June 2019. This Act provides for the imposition of a tax on the greenhouse gas emissions of a company (expressed in carbon dioxide equivalents (CO_2eq)) and matters connected therewith.

11.20.2 Tax rate

The tax rate was introduced at R120/tonne CO_2eq in 2019 and was expected to escalate at CPI+2% during phase 1 of the tax and then at CPI thereafter. However, in the Taxation Laws Amendment Bill (2022) a fixed rate was gazetted per annum up to 2030, starting at R159/tonne CO_2eq in 2023 and increasing annually up to R462/tonne CO_2eq in 2030. In the Budget Review, National Treasury outline their intention to continue to increase the rate thereafter.

11.20.3 Allowances

Schedule 2 of the Carbon Tax Act also lists the categories and maximum percentages of "tax-free allowances" that taxpayers may claim against each type of activity. There are three activities for which Eskom is currently liable. While emissions from category 1A1a (Generation) are able to receive a maximum of 90% total "tax-free" allowances, not all of these allowances are accessible.

11.20.4 Additional deductions during Phase 1 (ends December 2025)

The Carbon Tax Act allows Generation to make two extra deductions from the carbon tax liability. These deductions are only allowed until 31 December 2025. The first deduction is equivalent to the renewable energy premium that has been paid in a tax period. This is calculated based on the renewable energy purchases in each category, multiplied by the gazetted premium. The second deduction is equivalent to the amount equal to the environmental levy that has been paid in a tax period. For the previous carbon tax declarations, these two deductions have been sufficient to nullify the carbon tax liability. From 1 January 2026, when these deductions fall away, the full carbon tax liability is expected to be passed through.

11.20.5 Phase 2 of the Carbon Tax (from 1 January 2026)

As it stands, the carbon tax liability arising in January 2026 is expected to result in an amount as reflected in the primary energy section.

12 Operating Cost

12.1 Overall summary of operating costs

Operating costs include all costs involved with the day-to-day running of the business. Eskom's operating costs include employee benefit, maintenance, other expenses and allocated corporate costs. It should be noted that these costs are net of capitalisation and therefore represent the costs that are directly recoverable. The costs of operating and maintaining new assets are included in the operating costs.

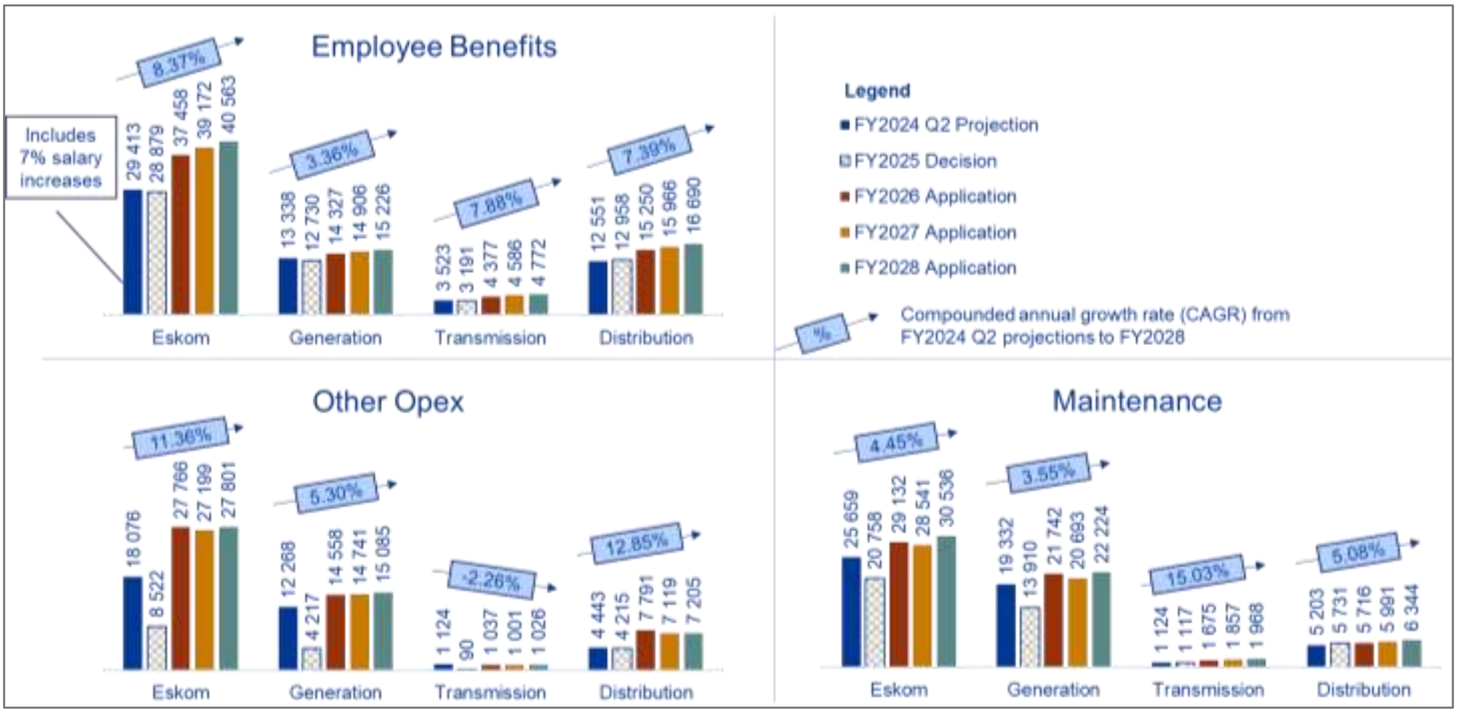
The next section will cover the operating expenditure (E) element of the building blocks to the allowable revenue formula.

$$AR=(RAB\times WACC)+E+PE+D+R\&D+IDM\pm SQI+L\&T\pm RCA$$

TABLE 31: DETAILED OPERATING COSTS

Operating costs (R'millions)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Employee benefit costs	28 207	32 246	35 346	37 458	39 172	40 563	42 208	44 081
Operating costs	41 481	48 114	45 674	56 899	55 740	58 338	59 020	62 136
Maintenance	22 045	25 659	29 010	29 132	28 541	30 536	29 918	32 504
Other operating costs	19 436	22 455	16 664	27 766	27 199	27 801	29 102	29 631
Operating costs before other income	**69 688**	**80 360**	**81 020**	**94 357**	**94 912**	**98 901**	**101 228**	**106 217**
Other income	(4 374)	(1 525)	(1 038)	(1 042)	(1 078)	(1 037)	(1 076)	(1 117)
Operating costs before Arrear debts	**65 314**	**78 835**	**79 982**	**93 315**	**93 834**	**97 864**	**100 152**	**105 100**
Arrear debt	12 774	11 622	14 706	8 914	9 917	10 752	12 037	13 310
TOTAL OPERATING COSTS	**78 088**	**90 457**	**94 688**	**102 229**	**103 751**	**108 616**	**112 189**	**118 410**

FIGURE 24: OPERATING COST TRENDS OVER MYPD 6 PERIOD



Eskom's projected operating costs, over the period FY2024 (Q2 projections) to FY2028 have compounded annual growth rate (CAGR) of approximately 5.4%. Analysis reflects that employee benefits have an average CAGR increase of 8.37% in this horizon. This is mainly due to the wage settlement at 7% (for bargaining unit) for FY2023 to FY2025. Maintenance costs have an average increase in CAGR of 4.45% over the period. The other operating costs see an increase in CAGR of 11.36% over the period.

Meaningful comparisons could not be made to the NERSA decision for FY2025, due to decisions being made on the basis of previous decisions. NERSA has not provided any analysis for its previous decisions. For the sake of comparison, a CAGR of 14.5% is calculated from the NERSA FY2024 decision to FY2028 operating cost application. This demonstrates the inadequacy of NERSA's previous decisions. As is illustrated in the figure above the NERSA FY2025 decision is on par or significantly below the Eskom FY2024 (Q2 projection). Eskom Generation has been severely impacted in the maintenance and other operating expenditure categories. Thus, Eskom had to make decisions based on the need to continue to operate for the benefit of providing the service.

12.2 Employee Benefits

Workforce optimisation was identified as a major component to drive internal efficiencies, increase productivity and lower operating costs. Approximately 80% of Eskom's staff complement belongs to the bargaining unit and 20% are positioned at managerial level. Eskom has recently relinked all service functions back to operations. The aim of the relinking process is to maximise decision-making, improve levels of accountability at the right levels of business, improve operational and financial efficiencies, maximise execution of strategy and operational plans, financial efficiencies and effective resource allocation and usage, including monetary and personnel.

Employee benefit costs are inclusive of cost to company remuneration and other employee related expenditures such as the skills levy, workman's compensation contributions, training, professional fees, overtime, contingency travel costs as well as labour recoveries for capital projects. The employee benefit costs for staff working on capital projects are directly allocated to the respective projects (capitalised) and recovered over the life of the capital asset through amortisation when the asset is depreciated. These costs are therefore excluded from the employee benefit costs.

Employee benefits costs are influenced by three main factors:

- Staff complement
- Employee benefits increases
- Level of remuneration

12.2.1 Staff complement

The planned number of employees is assuming to decrease. This will occur through planned attrition or alternates that support savings initiatives and efficiencies.

12.2.2 Employee benefit increases

When comparisons are made to Eskom's employee benefit escalations, they are either to the overall generic labour market (Market move) or to average settlements (for bargaining unit). The employee benefit costs comprise of direct remuneration (salary, pension, medical aid, bonus, overtime) and indirect remuneration (training and development, temporary and contract staff).

In assessing Eskom's market position the following is important:

i. Eskom has consistently benchmarked the salaries and related benefits of all levels of employees to ensure meaningful market alignment. For this purpose, Eskom participates in market surveys conducted by both the Deloitte Salary Survey and the PE Corporate Services salary survey. The two surveys cover 850 South African employers, and more than 1.5 million employees. This process allows for the meaningful comparison of Eskom remuneration levels within the broader labour market.

ii. Eskom operates from more than 450 geographic worksites across the country placing strain on the supply and retention of skills in general. The extent of and the duration of technical training and safety authorisation of employees deployed on the Generation, Transmission and Distribution side of the business, further requires that measures are put into place to stabilise the work force and minimise turnover.

iii. As a responsible employer and with due regard to the social and economic challenges, salaries at lower level of the business are positioned above the market median, however managerial level remuneration are closely aligned with the market.

12.3 Operating and Maintenance costs

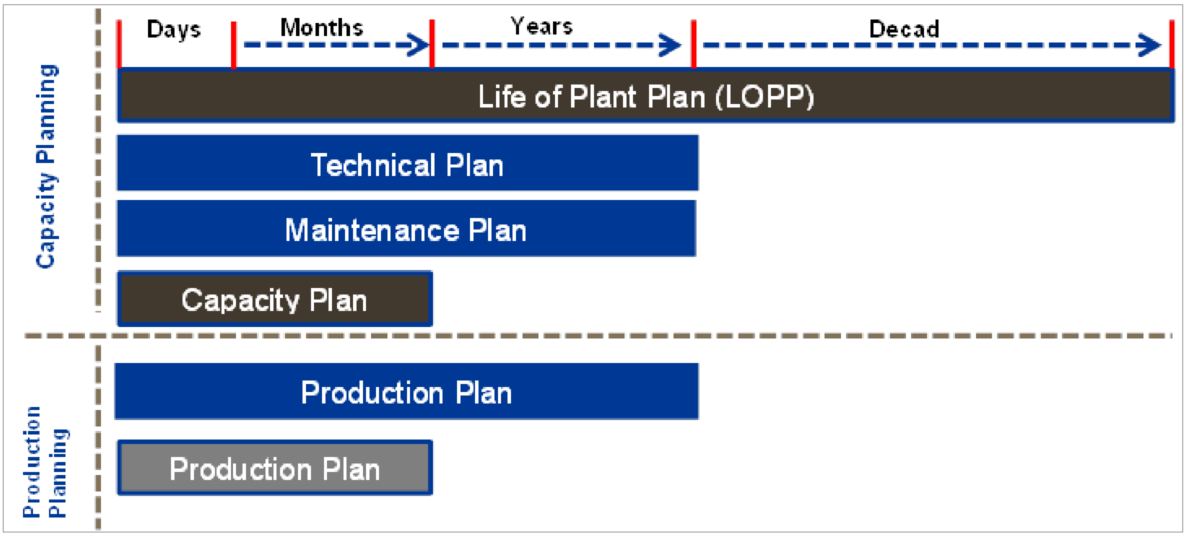
As the business strives to accelerate maintenance programmes, and with the ageing of plant, it is expected that maintenance costs should increase.

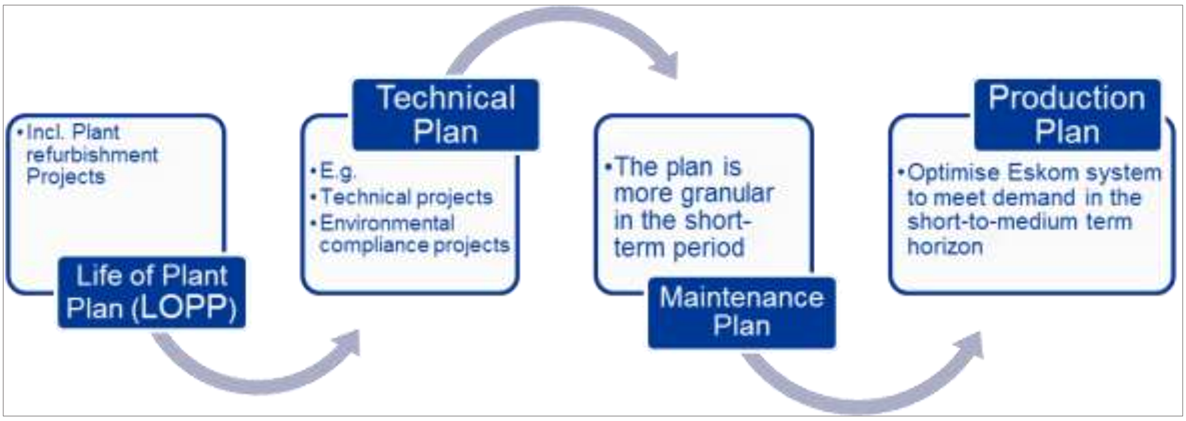
12.3.1 Generation maintenance

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.

FIGURE 25: MAINTENANCE PLANNING OVERVIEW





The LOPP is a plan of major maintenance and refurbishment interventions that are required over the life of the station. 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. However, generic rules exist:

- General Overhaul (GO): Every 10 – 12 years plant shutdown to do inspection and repair of turbine & generator.
- Mini GO: Every 5 - 6 years inspection of low-pressure turbines and statutory pressure test

- Interim Repair (IR): 18 – 36 monthly plant is shutdown to inspect and repair the boiler components
- Boiler Inspection (IN): Between IR's an inspection is carried out to review the condition of the boiler and scope the next outage

Opportunity maintenance frequently leads to the above schedule being modified which gives rise to adaptions of the sequence, but every effort is made to recover the sequence to ensure plant safety and operability.

Maintenance activities are prioritised by scheduling outages according to the following:

- Immediate safety risk as per the Emergency Response Action Plan (ERAP) inclusive of any emerging technical threat which is deemed to pose immediate and significant personnel or plant risk
- Statutory such as pressure tests
- 'Licence to operate' risks such as possible major contraventions of legislation
- Philosophy/Reliability scope is included in the outages based on the durations available

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.

12.3.2 NTCSA (Transmission)

The NTCSA's maintenance philosophy addresses statutory requirements, safety of assets and people as well as plant performance. The expanding transmission network requires additional resources to monitor and maintain assets. The cost of maintaining the transmission network is influenced by the geographical size of the network, condition as well as the increasing asset base. Planned outage constraints which require specialized skills and equipment to perform live line maintenance has an impact on maintenance costs. The maintenance revenue requirement further considers the increase in the asset base, inflation as well as deriving efficiency improvements.

The Grid is managed on a regional basis to perform operating and maintenance functions for substation plant, protection and control systems as well as line and servitude assets. This includes work planning, safety and environmental risk management as well as security support functions. The regional Grid Business Units are responsible for operating and maintaining the transmission plant in a safe and effective manner, restoring the network following fault incidents, sustaining the required quality of supply, interfacing with customers and ensuring that business objectives are achieved.

12.3.3 Distribution

Eskom Distribution's maintenance regime includes both preventative and corrective maintenance. Preventative maintenance refers to planned maintenance activities on assets whilst corrective maintenance refers to unplanned or fault activity.

The objective of maintenance is to ensure that:

- Asset condition is managed over the asset life cycle.
- Regulatory and statutory requirements are adhered to (Safety, Health and Environment).
- The technical performance focusing on interruptions and restoration time are in accordance with required performance levels.

The key drivers for the maintenance expenditure include the following:

- **Environmental and safety consideration:** To ensure safe operation of the network with a minimum impact to the environment.
- **Asset Base:** Geographically, the distribution network spans a landscape of approximately 53 476 km of distribution lines, 310 127 km of reticulation lines, and more than 8 376 km of underground cables in South Africa, this represents the largest power-line system in Africa. Based on history the asset base grows by approximately 4% per annum. This will increase the maintenance requirements in both the preventative and corrective (fault) environments.
- **Network performance:** Networks need to perform in line with design requirements supporting compliance to technical performance KPIs.
- **Quality of service to the customer:** Apart from supply availability, quality of supply parameters (voltage regulation, voltage dips, voltage unbalance etc.) must comply with regulatory requirements.
- **Sustainability of network infrastructure:** The network infrastructure is ageing and with limited capital investment leading to sub-optimal performance of network.

12.4 Other Operating Expenses

Included in this category are costs such as insurance, IT (information technology), fleet costs, legal and audit services, security, travel expenses, billing costs, connection/disconnection costs, meter reading, vending commission costs and telecoms.

- Insurance cost increases reflect the increase in the asset base as well as global premium increases. Factors that influence cover and pricing include insurance claim trends, loss ratio performance, value of insurance excess, new-build programme, re-insurance costs, increases in insured asset values and risk management efforts.
- The increase in Security expenditure is due to increased initiatives by Eskom to safeguard assets, combat theft incidents and mitigate the related risks.
- Telecommunication services is required for supervisory control and data acquisition (SCADA) and enabling remote access to fault recording systems as well as control centre communications.
- Meter reading - reading of Small Power Users (SPU) and Large Power User (LPU) billed customer meters are done mostly on a quarterly basis.
- Disconnection and Reconnection costs - costs incurred to manage outstanding debt by disconnecting non-payers and reconnecting once the payment is made.

12.5 Research, Testing and Development

The electricity industry is going through significant challenges driven by technology disruptors as well as market, policy and industry drivers. The power utility needs to respond to these challenges with the need for greater flexibility, rapid technology advances across the entire value chain and adapting to changing business models. Balancing social, environmental and economic imperatives relies heavily on technology development and breakthrough to provide a way forward when all other routes appear blocked. Eskom Research, Testing and Development (RT&D) is therefore dedicated to finding technology solutions that can be applied primarily within Eskom to ensure it fulfils its mandate to South Africa. '*We are predominantly a technology early follower'* - Except for a few carefully chosen areas, Eskom does not wish to lead technology development. Rather it will focus on technology identification, acceleration and application, not technology development.

Eskom is a needs driven organisation focussed on the systematic acquisition of knowledge and the application, development, refinement or demonstration of new and innovative technologies and solutions to satisfy Eskom's operational and strategic requirements through centres of expertise.

12.6 Insurance

Escap SOC Ltd ("Escap"), a wholly-owned subsidiary of Eskom, is the primary insurer for Eskom other than where Escap does not have the required capacity and/or expertise, mainly nuclear risks.

The main benefits that Eskom derives from having Escap as a primary insurer are:

- Generally, the components of an insurance premium include claims costs, commissions, administration expenses, contingency allowances and profit. Escap's pricing model does not include commissions and profit. Therefore, the insurance premiums charged by Escap are lower than the external market premium.
- The premiums that are not utilised to pay claims and other expenses are retained and invested by Escap. In the absence of Escap, this retained income would have benefited the external markets.
- Provides a protection from the volatility of the insurance market by mitigating against insurance premium increases that are due to market conditions as opposed to increase in risk.
- Promotes risk management through engineering risk surveys.
- Provides direct access to the reinsurance market which in turns allows for negotiation of favourable reinsurance premiums.
- Ability to provide insurance covers that are not available in the conventional insurance markets.

13 The need for Integrated Demand Management

The role of IDM is to influence the electricity demand profile of its customer base for the benefit of the Distribution business, the entire Eskom value chain, and the country. Over the past 14 years, while Eskom experienced a supply shortfall, IDM focused mainly on energy usage reduction and load management. It is anticipated that the country will continue experiencing a shortfall in generation capacity in the short to medium term.

In particular, demand management (DM) measures will also support Distribution System Operations (DSO) by providing flexible services (dispatchable supply and demand) to maintain adequate operating reserve levels, reducing evening peak demand in the industrial, commercial, agricultural, and residential sectors to manage grid stability and congestion on the local and national networks. Furthermore, DM measures can optimise capital expenditure on constrained networks by deferring network upgrades through localised demand-side management programmes, where feasible. Experience has proven the valuable contribution IDM and DR programmes can make to stabilising the electricity system.

The demand/supply situation is cyclical, and maintaining DM capacity is essential. More so, having DM capacity that uses the principle of efficient energy when required by the business as a means to support both excess and constrained supply situations will be a considerable asset to the industry and the economy.

14 Governance challenges are being addressed

Eskom acknowledges that there have been governance failures in the recent past. Adjustments in tariffs would need to be made for any recovery from the outcome of the investigations and actions related to governance failures. Eskom takes direction from NERSA in this regard. On 7 March 2019, the NERSA Media statement as confirmed by the NERSA Chairman (at that time) at the media briefing was as follows with reference to previous revenue decisions:

"The energy regulator also considered that Eskom conceded that certain governance failures occurred in Eskom. However, at the time of the above decisions and although some of the adjustments were effected, the extent of the governance failures or amounts associated therewith had not been fully quantified. The energy regulator may initiate its own investigation into the governance failures in Eskom and may effect adjustments to Eskom's revenue based on the relevant outcome of its investigation and/or those undertaken by bodies or entities, including, but not limited to, Eskom, National Treasury, the Special Investigating Unit, the South African Directorate for Priority Crime Investigation (Hawks), the Parliament of the Republic of South Africa, or any commission of enquiry as and when they are concluded or a conclusive outcome is reached and the costs associated therewith have been quantified." Eskom is on record in support of this approach as clarified during previous submissions to NERSA.

Specific initiatives to address governance failures include the following:

14.1 Restoring Eskom's reputation as a trusted corporate citizen

Eskom has intensified its focus on environmental, social and governance (ESG) matters to rebuild Eskom as a high-performance, ethical and values-driven organisation. Furthermore, our ESG framework has been enhanced, in support of our Code of Ethics, to factor in broader legal and governance issues, including Eskom's response to the effects and aftermath of state capture as well as criminality, in the form of fraud, corruption, theft and sabotage. Over time, these issues have eroded Eskom's operational and financial sustainability as well as its reputation and relationships with key stakeholders. The Board acknowledges that addressing these matters will be a lengthy process and recognises that more internal work is required to eradicate the scourge of criminality that affects the organisation.

14.2 Board investigation into the allegations by the former chief executive

During an interview with eNCA in February 2023, Mr André de Ruyter made certain allegations and alluded to the involvement of Government officials in fraud and corruption, without first disclosing the information to the Board or consulting the Board on the matter. The Board could not condone Mr De Ruyter's actions and reached a mutual agreement with Mr De Ruyter to revert to the original notice period of 28 February 2023 set out in his resignation letter; he was not required to serve the balance of his notice period and was released with immediate effect on 22 February 2023. During the interview, Mr De Ruyter publicly disclosed information on alleged fraud and corruption affecting Eskom, which has prompted the Board to initiate an investigation to determine whether there are any gaps between what is already known and under investigation by Eskom and what was alleged in the interview. The Board is taking these allegations very seriously. Should its investigation find that the allegations have merit, they will be dealt with through the appropriate channels. Eskom is cooperating with all external investigations and inquiries related to these matters.

14.3 Eskom's response to the findings of the Zondo Commission

Eskom has established a dedicated state capture task team which is assisted by external legal counsel. The task team has completed its review of the report of the Zondo Commission and developed an implementation plan to address the Commission's recommendations and ensure appropriate legal remedies are pursued. The recommendations include instituting criminal charges, ensuring appropriate consequence management against employees and suppliers, pursuing director delinquency proceedings and civil recovery of financial losses suffered by Eskom.

14.4 Initiatives to address implicated individuals and companies

14.4.1 Consequence management of delinquent employees

Employees implicated in state capture were dismissed or resigned in early 2018. There are currently no outstanding disciplinary actions against individuals highlighted in the Zondo Commission report and no implicated individuals are currently employed by Eskom.

14.4.2 Director delinquency proceedings

From a legal perspective, the most effective avenue to charge former directors and officials is through delinquency proceedings under the Companies Act, 2008. DPE is coordinating this process across all SOCs.

14.4.3 Blacklisting of suppliers

Eskom has placed a provisional block on all implicated suppliers, preventing new contracts with these suppliers. Eskom is awaiting the outcome of related court cases before following the necessary governance processes to formally blacklist any suppliers.

14.4.4 Initiatives to enhance proactive management of fraud and corruption

Eskom is also re-evaluating the effectiveness of its approach to crime, fraud and corruption in line with the recommendations of the Zondo Commission and external audit findings. This involves reviewing and making relevant changes to policies, processes, systems, controls and structures where necessary.

14.4.5 Review of policies and procedures

Our task team has reviewed Eskom’s supply chain management and human resource policies and procedures and made recommendations to improve the implementation of consequence management and enable sanctions to take place more effectively going forward. We are also implementing automated systems in the procurement of goods and services and management of spend, including price check tools, digitalisation of stock control and e-auction systems, to proactively address fraud- and corruption-related risks.

14.4.6 Crime landscape risk assessment

We are conducting a full assessment of Eskom’s crime risk management landscape in partnership with an independent service provider. This initiative is aimed at identifying risks related to bribery and corruption, financial crime, physical asset crime, cybercrime and money laundering, to inform Eskom’s approach to addressing and combating these activities.

14.4.7 Single investigative unit

Eskom’s Forensic and Anti-Corruption Department performs independent forensic investigations into cases of fraud, corruption, and general irregularities, supported by a panel of external investigators. In addition, Eskom has many other functions which are responsible for investigating and responding to crime and other unethical behaviour. The existing approach of having multiple investigative functions, operating in an uncoordinated manner at times, is not yielding the desired results. To enhance our effectiveness in preventing and responding to these matters, we have embarked on a programme to consolidate our multiple investigative functions into a single investigative unit.

14.5 Eskom's Fraud Prevention Plan

We have implemented a Fraud Prevention Plan which is reviewed and updated annually. The key objectives of the plan include:

- Improving Eskom's ethical culture and legislative compliance
- Adopting and embedding a zero-tolerance approach to fraud and corruption
- Raising awareness of fraud through fraud prevention campaigns and training interventions
- Improving transparency and credibility of the procurement process
- Encouraging members of the public to blow the whistle on fraud, corruption and financial misconduct by publicising Eskom's whistle-blowing channels
- Establishing an intelligence-driven forensic investigation capacity
- Supporting management in the implementation of consequence management, and improving oversight and management accountability

14.6 Whistle-blowing and conflict of interest management

All stakeholders, including employees, are encouraged to report suspected incidents of unlawful or irregular conduct involving Eskom's directors, employees or suppliers through our whistle-blowing channels. These channels are managed by an independent service provider to ensure the integrity and confidentiality of the process.

14.7 Improving consequence management

A number of interventions have been put in place to improve the effectiveness of consequence management processes. These include the establishment of an external disciplinary tribunal, to expedite disciplinary action and address the backlog of cases, training of disciplinary chairs and case presenters, as well as monitoring and evaluation of long outstanding disciplinary actions at executive and Board level.

14.8 Addressing security risks

A Safety and Security Work Stream has been established under the Energy NATJoints and is chaired by the National Commissioner of Police, to focus specifically on combatting criminal activities affecting Eskom's operations as well as the criminal cases reported by Eskom to law enforcement authorities. An Executive Security Steering Committee has been established within Eskom to address security risks relating to criminal acts, including theft, vandalism and sabotage incidents.

15 Financial constraints need to be addressed

15.1 Economic climate

While 2023 had seen economic activity weakened, central banks maintained their restrictive monetary stance. This paid-off without too much economic damage as inflation drifted towards central bank targets. Labour markets remained strong, particularly in developed economies, serving as both a safety net and a launchpad for economic growth. With this firm foundation, further consolidation is required in 2024. This is to ensure that Government reserves are replenished to counteract any unexpected shocks, improve debt ratios and appropriately position fiscal stimuli to maximise fiscal multipliers. This is easier said than done, given that many countries are going to the polls this year.

With the South African national elections schedule in May 2024, the Minister of Finance sort to strike a balance between fiscal discipline and social wage and labour demands. The South African fiscus remains heavily constrained and in great need of rehabilitation. A main budget deficit is projected over the medium-term while tax revenue collection is likely to remain constrained. Corporate tax revenue has come under pressure as manufacturing and mining sector activities are hindered by inconsistent electricity supply and logistical challenges. Personal income tax is the largest contributor to the government’s revenue. It is expected to remain under pressure as new job prospects are dim and the unemployment rate remains stubbornly high. According to a SARB 2021 working paper, the South African government has struggled to maintain a fiscal multiplier of 1 times since 2014 and some years has even had a negative multiplier (Ref: South African Reserve Bank Working Paper Series WP/21/07). This is particularly evident in the composition of government expenditure, which has a heavy bias towards consumption.

As fiscal conditions continue to deteriorate and debt-to-GDP remains above 70%, RSA credit spreads will continue to widen with adverse effects on the rand. A weak rand results in higher import inflation, further adding to the SARB’s reluctance to shift to a more accommodative monetary policy stance. Rates are expected remain higher for longer, with a limited downside bias towards the end of the year. CPI averaged 6.0% for 2023, with a noticeable improvement towards the latter parts of the year mainly due to lower fuel prices. This trajectory is likely to continue during 2024 with CPI projected to average 4.9% for the year. The South African economy grew by 0.6% in 2023, down from the 1.9% in 2022. GDP recovered to 0.1% q/q in the fourth quarter after contracting by 0.2% in the preceding period. This recovery was occasioned by improved mining and manufacturing activities partly due to lower loadsheding during the period under review. This recovery means that South Africa has narrowly avoided a technical recession.

The United States 60th presidential election is scheduled for the 5 November 2024. Incumbent President, Joe Biden, and his predecessor, Donald Trump, have been nominated for the Democratic and Republican parties, respectively. Trump has emerged as a strong candidate. Should the Republican party win the upcoming elections, there will be significant changes in domestic and foreign government policy. US GDP has surprised on the upside at 2.5% annual rate for 2023. This growth in economic activity has resulted in a healthy labour market, with the unemployment rate remaining steady at 3.7% during January 2024. As inflationary pressures ease and supply challenges get resolved the fed will be inclined to respond. The average CPI for 2023 moderated to 4.1% as compared to 8.0% in the previous year.

Economic growth in Europe is expected to remain sluggish. The Eurozone experienced a technical recession mid-2023. It recorded annual average growth of 0.1% for the year. Meanwhile the UK economy contracted by 0.2% during the same period. The European Central Bank and the Bank of England are expected to cut rates during the second half of 2024.

The Chinese economy grew by 5.2% in 2023, benefiting from the fiscal stimulation packages and a fairly accommodative monetary policy stance. The Chinese economy is expected to continue its recovery from the damage of Covid and the collapse of its property market. In contrast, the Bank of Japan has kept policy rates negative in 2023 in the hope of boosting demand and stimulating some inflationary pressures.

Financial markets are pricing in lower inflation, lower interest rates, and recovering but subdued economic growth. Commodities prices are expected to be subdued as supply side constraints are likely to be overshadowed by weak demand. Political uncertainties and geopolitical tensions could result in higher market volatilities.

15.2 Liquidity challenges

Liquidity remains one of our biggest challenges, hampering our ability to achieve financial and operational sustainability. Access to cost-effective funding remains restricted due to decreased investor confidence because of continued poor financial performance, saturated borrowing capacity and recent credit rating downgrades. Inadequate price increases granted by NERSA as well as escalating municipal arrear debt further contribute to our liquidity constraints. These liquidity and solvency risks pose an inordinate threat to Eskom's ability to continue as a going concern. To improve liquidity, we have restricted organisational cash requirements through targeted savings on operating and capital expenditure. We had to rely on Government support to maintain a positive cash balance at year end, with increases in equity. We have always deemed it prudent to maintain a liquidity buffer that covers an average of three months of organisational cash flow requirements. Due to high debt servicing obligations, maintaining the liquidity buffer at acceptable levels continues to be a challenge.

15.3 Financial sustainability

We have to reduce our reliance on debt funding as a source of liquidity – equity injections by the shareholder will assist in reducing this reliance in the short term and help to improve liquidity. Although Government's equity support addresses our liquidity requirements, it does not adequately enhance our long-term financial sustainability. The only way to achieve financial sustainability is to improve operating cash flows that results in positive free cash flows, with a strong focus on moving to a prudent, cost-reflective tariff.

We acknowledge the importance of cost savings to improve liquidity, with a focused cost curtailment programme over the next three years. Nonetheless, as we've stated before, cost savings alone will not be sufficient to improve our financial health. For Eskom and the electricity supply industry to continue to operate and maintain its assets in a reliable state, the price of electricity must migrate towards cost-reflectivity to ensure Eskom's long-term financial sustainability. Without a cost-reflective tariff path, we will remain reliant on Government support, which implies that the taxpayer will continue to foot the bill for the revenue shortfall, which is contrary to the "user pays" principle.

Our overarching objective remains to return Eskom to financial and operational sustainability, while improving transparency of reporting to the shareholder and the broader public in order to regain trust.

15.4 Essentail to migrate towards cost reflectivity

In 2007 National Treasury commissioned an independent assessment of the electricity sector which commented that "Government should formulate an electricity pricing policy such that NERSA could award overall revenue levels to Eskom that would enable a migration of prices to Long Run Marginal Costs". The 2008 Electricity Pricing Policy states that "It is recognised internationally that cost reflective tariffs, as reflected by Long Run Marginal Cost (LRMC) representing the true economic cost, are the best price signal."

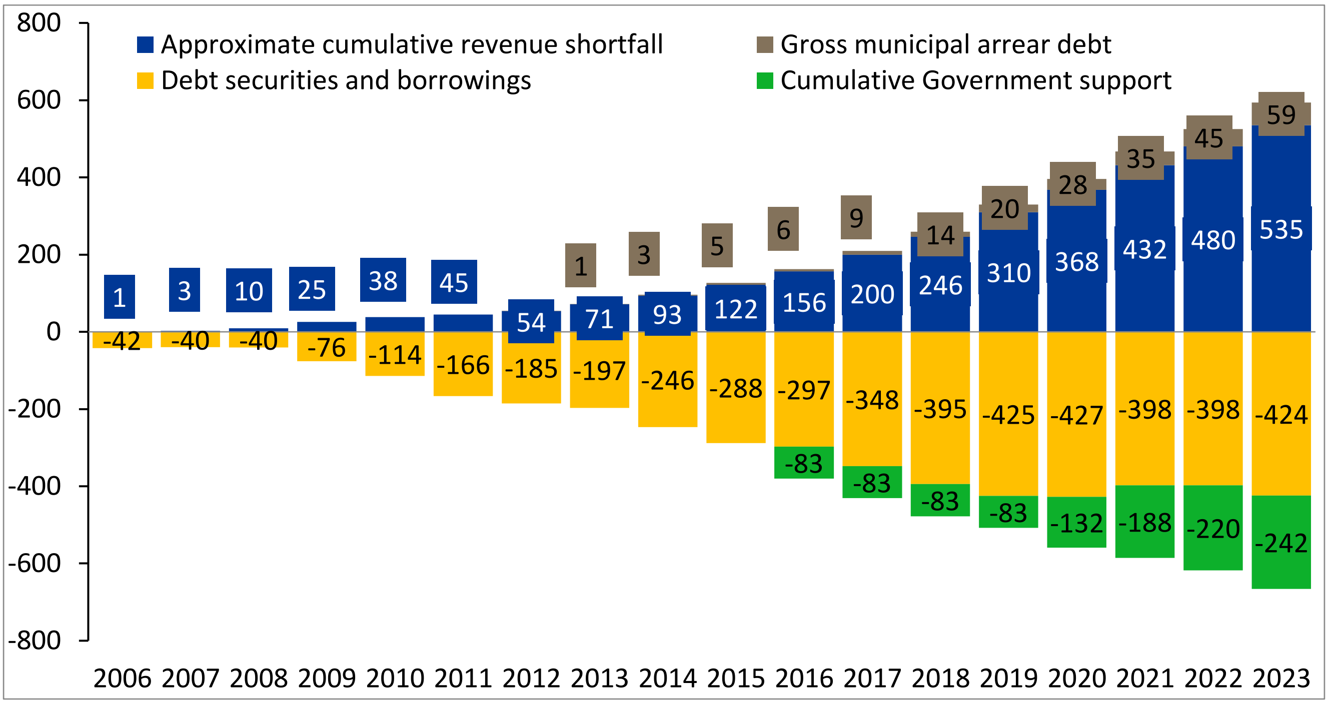
Electricity prices close to the level of LRMC are thus not only required for the purpose of sending the correct price signals, it is also required to ensure the long term viability of the electricity industry. Such prices ensure that the full cost of the production of electricity (and nothing more) is recovered namely the capital investment, the fuel cost and the operational and maintenance cost, over the asset life cycle, in a profile which is not overly “front loaded” (i.e. higher at the beginning of the asset’s life cycle than at the end). It thus results in very stable price levels without price shocks when replacement or expansion of capacity takes place.

It is often argued that higher electricity prices will result in negative macro-economic consequences. This is however not supported by independent economists. In another report commissioned by National Treasury in 2003, it is argued that “continued sub-economic pricing (prices below long-run marginal costs) in the industry ironically run the risk of increasing real costs in the economy (by reducing allocative efficiency). Furthermore, sub-economic energy prices benefit energy and capital intensive growth, and places labour and skills intensive development paths at a disadvantage. Proper economic pricing of power will reverse skewed incentives in the long-term and support South Africa’s primary economic aim, which is to establish labour absorbing development paths”. It further argues that improved macro-economic allocative efficiency would result from “economically efficient prices” and thus actually reduce the cost of doing business in South Africa in the long run (“Moving to cost reflective prices will save real costs in the economy…by encouraging efficient use of energy and capacity (including demand side investments) which, if electricity service is priced correctly, will be cheaper in real resource terms, than new supply capacity…”

When Eskom makes a revenue application to NERSA, all it expects from a revenue determination is for **efficient costs** to be recovered through a tariff application. This is motivated in detail when a revenue application is made. The criteria applied are strictly guided by the relevant legislation and NERSA rules. However, NERSA has not allowed Eskom to recover its efficient costs at a fair return for many years. The efficient cost for a utility can be independently determined using the particular South African circumstances. As judged recently, NERSA has not been fulfilling its legislative mandate in this regard.

The following figure from the FY 2023 Integrated Report, illustrates the dire circumstances that Eskom has been operating in for more than a decade. This is as a result of various factors that Eskom has faced over the years, i.e. balancing competing objectives (cost reflective prices vs developmental role, perception that prices are high etc.) as well as a result of NERSA granting inadequate revenues to allow for Eskom to operate. In essence, Eskom has not recovered its efficient costs and a fair return. The cumulative shortfall in the revenue (which is what was applied for and what NERSA granted) corresponds with the increasing debt burden. This could be translated into Eskom having to borrow to keep continuing to provide an electricity service. The added burden of the increasing arrear debt – mainly from Municipalities, exerts further pressure on Eskom's sustainability. In more recent years, growth in debt has been tempered by Government equity support, with Eskom's debt book reaching maximum carry limits based on the level of Government guarantees available as well as cost of debt servicing.

FIGURE 26: IMPACT OF SHORTFALL IN REVENUE DECISIONS ON ESKOM'S FINANCIAL POSITION (R'BN)



One of the key reasons for a significant shortfall in revenue determinations by NERSA is the actual return on assets being very different from the weighted average cost of capital and averaging at approximately 0%. Eskom has continuously tempered the ROA applied for over the years (phasing in returns) to provide for a tolerable price increase. This approach has not fared well for Eskom over the years as it did not provide Eskom the ability to build up sufficient reserves over the years and has contributed to the perception that prices must be low.

Another key reason is incorrect RCA decisions. The RCA mechanism was meant to allow Eskom the opportunity to achieve the initial revenue that was allowed during the revenue decision. It allows to increase/decrease the allowed revenue due to changes in assumptions or costs that are subject to re-measurement. Examples include change in exchange rate, securing energy from a different source than originally assumed in the NERSA decision. However, in many instances the RCA addresses a poor NERSA revenue decision. Examples include inadequate coal price assumption or basing employee benefit costs on a situation 10 years prior.

Eskom has reviewed all NERSA RCA decisions from 2015 to 2021. The High Court has found that NERSA has not correctly implemented its methodology resulting in a R62bn shortfall in revenue being recovered by Eskom over a seven-year period. For the amounts that NERSA has determined, approximately R20bn is lost due to the time value of money where recovery of efficient revenue is delayed by 4 to 6 years. Eskom has also reviewed the NERSA MYPD 4 decision where R69bn was incorrectly deducted from the return on assets in FY 2020 to 2022. After significant delays in legal proceedings, NERSA agreed through Courts that it incorrectly deducted the R69bn. This amount is now being recovered from FY 2022, 2024 - 2027. Additionally, the time value of money lost is approximately R36bn.

15.5 Government's plan to address eskom's debt burden

The Minister of Finance announced Government's debt relief plan for Eskom during the 2023 National Budget Speech in February 2023. The Eskom Debt Relief Act was subsequently promulgated on 7 July 2023 and will provide relief of debt servicing costs of R254 billion over the next three years. The first component will provide direct support of R184 billion to address our debt and interest payments as they fall due over the next three years. This support will initially take the form of a subordinated loan, which will be settled in ordinary shares on a quarterly basis once we have demonstrated, to National Treasury's satisfaction, that we have complied with the conditions attached to the support. The second component will see Government take over R70 billion in Eskom debt commitments (both capital and interest) in 2026. The conditions announced during the 2023 National Budget Speech include that:

- Eskom's capital expenditure is restricted to transmission and distribution activities. The only capital expenditure that may be undertaken for generation relates to minimum emission standards, flue gas desulphurisation and required maintenance. No other greenfield generation projects will be allowed during the debt relief period
- Eskom may not use the proceeds from the sale of non-core assets for capital and operating needs. All proceeds from the sale of non-core assets, including Eskom Finance Company SOC Ltd and any property sales, will be used for the debt-relief arrangement
- No new borrowing will be allowed from 1 April 2023 until the end of the debt relief period, unless written permission is granted by the Minister of Finance

- Positive equity balances in Eskom's derivative contracts (swaps/hedges) may not be used to structure new debt or loan agreements without the approval of National Treasury. Any such balance may not be used as "margin financing" for another derivative contract or derivative overlays
- The debt relief can only be used to settle debt and interest payments
- Eskom may not implement remuneration adjustments that negatively affect its overall financial position and sustainability

National Treasury has subsequently clarified that the restriction on capital expenditure for generation will still allow for the completion of existing projects, such as Medupi and Kusile, the repowering and repurposing of Komati, battery energy storage, the life extension of Koeberg, as well as sourcing of nuclear fuel and investment in existing cost-plus coal mines. Greenfield generation projects may be undertaken, but only with the written approval of the Minister of Finance. The conditions to be attached to the Eskom Debt Relief Act, together with additional operational and financial conditions, have been finalised by National Treasury and DPE. The additional conditions aim to address key operational aspects including Generation plant performance, municipal debt recovery, skills development and further financial efficiencies.

The primary focus of Eskom's debt strategy going forward is to ensure strict adherence to the conditions attached to the debt relief package, to enable conversion of Government's subordinated loans to equity. This remains the only approach to deleveraging our balance sheet. Given the limitation on new borrowings, the debt relief package essentially requires Eskom to ensure that the balance of debt servicing costs, as well as the cash flows required for the capital investment programme, are fully funded through cash generated from operations. The debt relief package is expected to improve financia sustainability by assisting us with our debt servicing challenges. Based on financial modelling, our gross debt securities and borrowings balance is expected to reduce by around 40% over the next five years, to below R270 billion.

As is evident, the purpose of this debt relief package is to delever the Eskom balance sheet. The package is applicable for a three-year period and comes to an end during this application period. The Minister of Finance has clarified that the migration of the South African price of electricity towards cost reflectivity is an essential element of the package. This package addresses the decades of shortfalls in revenue determinations and requires NERSA determinations that allows for a further narrowing of the gap between towards cost reflectivity. The debt support would come to naught if the gap to cost reflectivity is not narrowed.

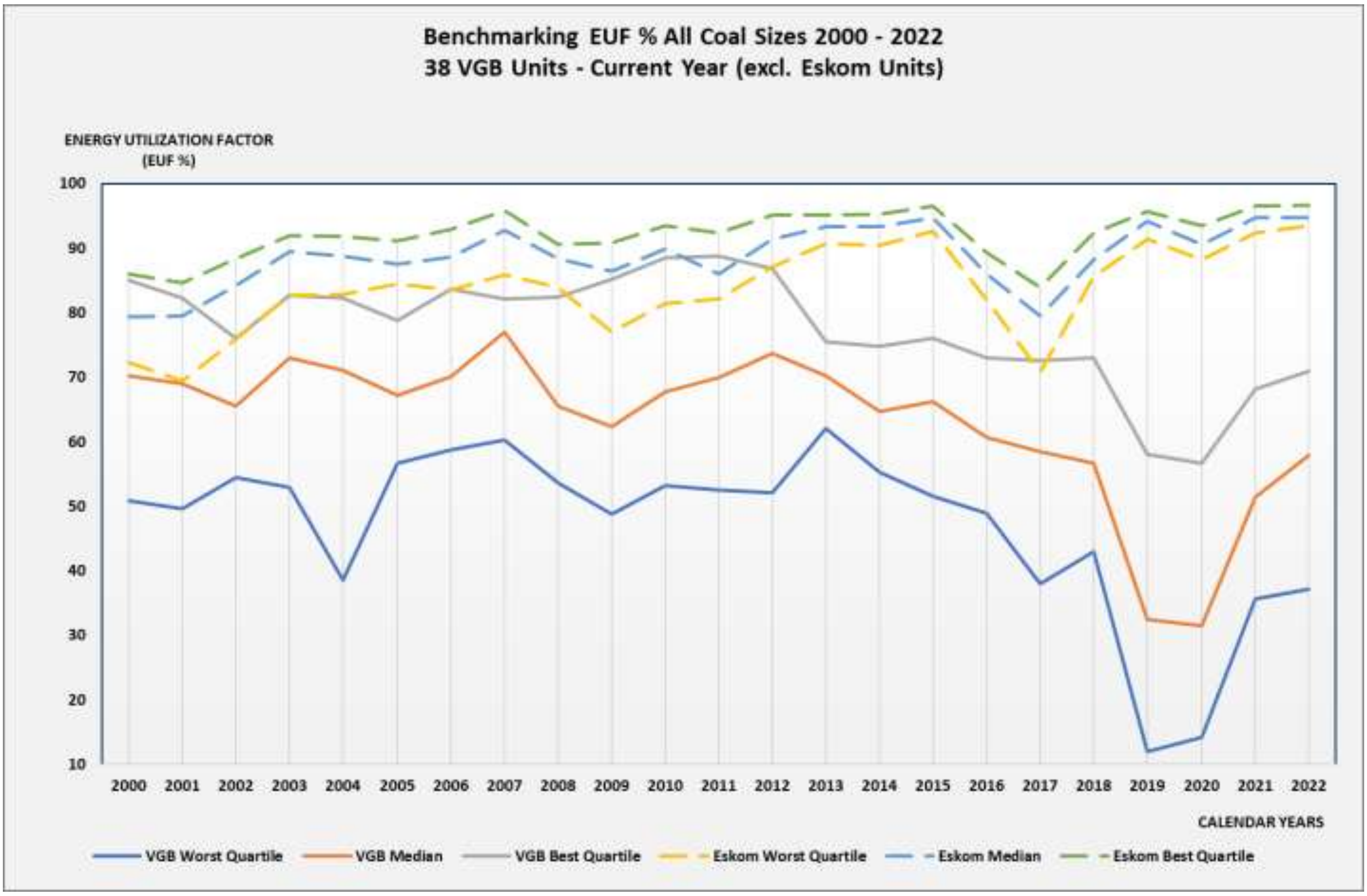
16 Generation context

The responsibility of balancing the supply with the demand of electricity and to ensure adequate capacity lies with the DMRE Minister. The IRP process lays out the requirements in terms of necessary capacity per technology to ensure that sufficient energy is made available in the country whilst balancing the various other priorities such as least cost and environmental considerations. In the short-term, however, Generation is cognisant of the negative impact of electricity shortages on the country's economy and does everything reasonable to ensure adequacy of supply. This has led, over a period of over a decade, to actions that may have had a long-term negative impact of the health of Eskom Generation's generating fleet.

Eskom had planned to shut down the remaining operating units at Camden, Hendrina and Grootvlei between January 2023 and September 2027. However, in response to the capacity shortage and to minimise or avoid load shedding, Eskom decided not to shut down any more units until at least 2030 which includes Arnot and Kriel units which were also due to shut down prior to 2030. In addition, Tutuka is no longer expected to shut down early by 2030, requiring funding in the MYPD6 period to enable running beyond 2030. This is known as Continued Operations and is does not involve life extensions or major upgrades and refurbishments. Despite this, significant, additional, previously unplanned, funding will be required for the maintenance and operations of these units.

The performance of Generation's generating fleet is below aspiration. Although there are many contributing and aggravating factors, the root cause of this performance is the government's decision in the 1990's that Generation would not build any more power stations. This led to the late start of the build programme and severe capacity constraints. This required that the existing plant had to be run exceptionally hard to meet the demand, accelerating the wear and tear on the ageing units. The graph below illustrates how Generation's coal-fired units were, for a period of about 15 years, run at an Energy Utilisation Factor (EUF) far higher than the international benchmark; and in the "red zone". For four years from 2012, Generation's lowest quartile was "run harder" than the top quartile of the benchmark stations.

FIGURE 27: UTILISATION OF GENERATION'S COAL FLEET VERSUS INTERNATIONAL BENCHMARK



At the same time, the financial and capacity constraints meant that Generation was not able to implement most of the "mid-life refurbishments" that are required in order to maintain and improve the performance of the stations as they age.

Although one expects performance challenges in newly commissioned stations, the performance of Medupi and Kusile as well as the pump-storage station, Ingula, were below aspiration. Once again, a major contributor, if not the root cause, is the capacity constraints due to the late start to the build programme. This resulted in a condensed design phase to accelerate the programme. Allied to the exceptionally long period, and related loss of skills and institutional knowledge, from the previous build programme where the design was executed in the 1980s, this contributed to the design faults that have resulted in an unacceptably high level of plant failures. These are being addressed with plant and procedure modifications and an improvement in performance has been seen.

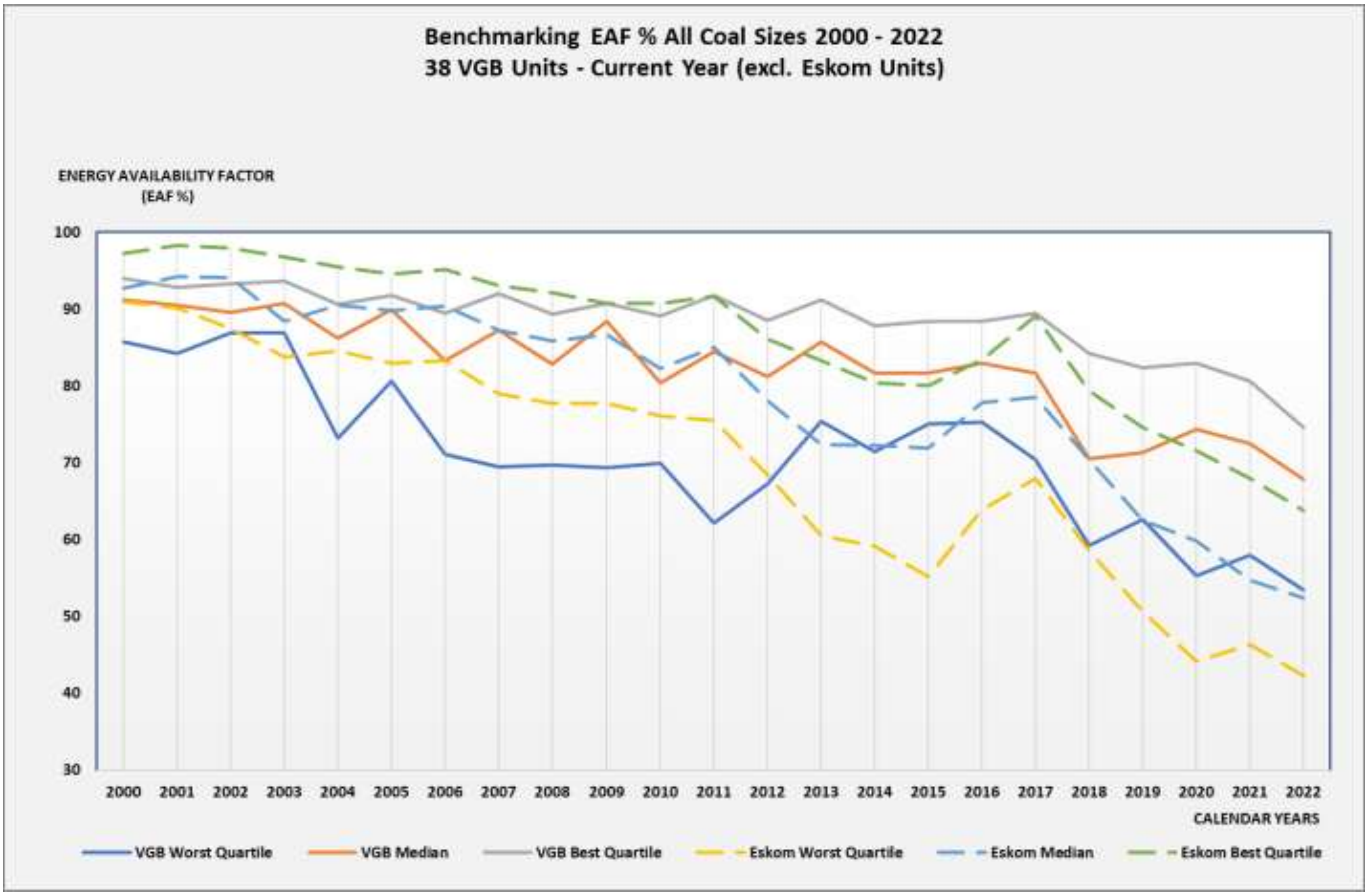
This all led to inadequate capacity to meet demand whilst leaving inadequate maintenance space to perform an ideal level of preventative maintenance, particularly mid-life refurbishments. As a power station reaches 25 to 30 years of operation, major systems and components need to be refurbished, replaced or upgraded to maintain and improve the performance of the stations. Allied to this, in the early 2000s, a requirement to reduce costs which meant that capital expenditure was constrained, and this also impacted on mid-life refurbishments, even when there was space to perform the maintenance.

The performance of Eskom’s Generation fleet continued to perform well up to 2012 with an availability of over 80%. However, Generation was operating in a constrained environment and had a *de facto* obligation to meet national electricity demand, particularly in the lead up to and during the 2010 World Cup. This required Generation to both defer maintenance and run the plant very hard when it was available. This obviously had a negative impact on the health of the stations and thus their availability due to increased unplanned breakdowns. The decline in plant availability from 2013 meant that even less capacity was available to meet demand and thus required the available plant to run even harder resulting in a “vicious circle”.

This situation was not sustainable and in subsequent years, planned maintenance levels and spend were increased despite the fact that this resulted in load shedding. This was essential but only possible because the Shareholder removed the Keep the Lights On (KLO) requirement from the Shareholder Compact from 1 April 2013. This increase in maintenance was the major contributor to the improvement in plant availability in FY2017 and FY2018. This improvement was, unfortunately, short-lived and availability started to decline again from late 2017. The reasons for this latest decline are many, complex and varied. The historical sub-optimal mid-life refurbishments and hard running of an ageing fleet (more than half – including Medupi and Kusile – over 40 years) still has the highest impact on plant failures, but shortages of experienced skills and staff morale, driven by consistent under-recovery through the tariff and current uncertainty are also amongst the contributing factors. Although the debt relief support from National Treasury has recently allowed for the early ordering of long-lead spares for outages, Generation still operates in a severely cash-constrained environment mainly due to extensive periods of receiving sub-cost reflective tariffs.

As illustrated above, the trend of high utilisation has continued and even the lowest quartile stations have, in general, been running harder, at a higher utilisation, than the VGB benchmark. Even without this exceptionally high utilisation, the ageing of the fleet, on its own, would lead to increased unavailability, particularly when not all the ideal mid-life refurbishments could be carried out due to financial and capacity constraints. This trend of a decreasing availability as a fleet age can also be seen in the performance of the VGB benchmark fleet.

FIGURE 28: GENERATION'S COAL FLEET AVAILABILITY VS THAT OF THE VGB BENCHMARK



Generation operates an ageing Generation fleet, notwithstanding the new stations recently completed with only 2 remaining Kusile units under construction. More than half of the stations and more than half of the coal-fired stations will be 43 years and older by the beginning of the MYPD6 period.

16.1 External Reviews recommendations align with Eskom recovery plans

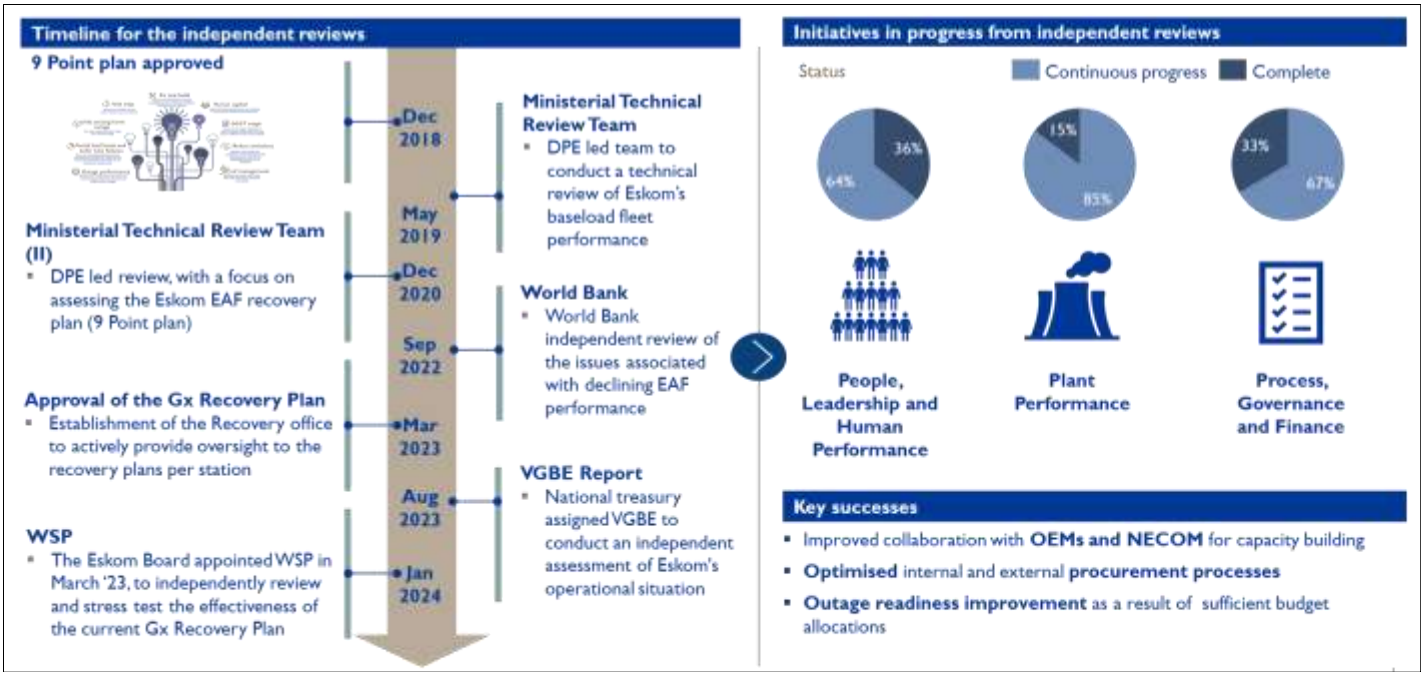
In 2023, National Treasury commissioned a review of Generation stations by a consortium led by VGB Energy (VGBe). Over recent years, there have been a number of reviews of the Generation business. These include two Department of Public Enterprises led Ministerial Technical Review Team reviews, the World Bank independent review and the Eskom Board appointed WSP review.

A comparative analysis of these reports has identified that some of the recommendations highlight recurring themes amongst these reports which indicated that there is a gap with regards to the effectiveness in addressing the recommendations. These themes can be divided into three categories, namely, People, Leadership and Human performance; Plant Performance; and Processes, Governance and Finance. The reports have thus been revisited to identify the implementation shortcomings and are being actioned and integrated into the Generation Recovery office tracking application to ensure oversight.

Multiple actions and programmes are already in place to address the shortcomings highlighted in the reports. Generation is managing the recommendations and actions and will continue to drive their implementation. Central organisational actions are being incorporated into the Generation recovery plans under the Recovery office and quarterly feedback will be provided to the Eskom Board. Since the Eskom Board approval of the Generation Recovery plan in March 2023, Generation is confident that significant progress is being made in addressing systemic organization challenges.

The recommendations of various independent reviews and responses have been consolidated as reflected in the figure below.

FIGURE 29 : CONSOLIDATION OF RECOMMENDATIONS MADE BY VARIOUS INDEPENDENT REVIEWS



17 Transmission Development Plan

17.1 What is Transmission Development Plan (TDP)

The TDP is a transmission licence requirement issued by NERSA, that emanates from the South African Grid Code, which states that "*The NTCSA shall annually publish a minimum five-year-ahead TS development plan by end October, indicating the major capital investments planned (but not necessarily approved).*" TDP addresses the Transmission network requirement to ensure a stable and sustainable network that can integrate new generation capacity and load requirements of the country, while maintaining minimum reliability (redundancy) standards commonly referred to as (N-1) and (N-2). In 2023, NTCSA was granted an exemption by NERSA from publishing the TDP 2023. The exemption was requested on the basis that the DMRE is still in the process of finalising the new IRP, which forms a critical basis for the requisite transmission network studies. Therefore, the new generation capacity assumptions of the TDP 2022 extended beyond the IRP 2019 period, it is still valid. The TDP indicated that 53GW of new generation capacity would be required by 2032, mainly from renewable energy sources, especially solar and wind. The TDP 2022, published in October 2022, forms the basis for future investments in transmission infrastructure and it focuses on new transmission capacity expansions and network strengthening requirements for the next ten years addressing required increased generation capacity.

17.2 The importance of the TDP

TDP is important in addressing capital investment required to replace assets that have reached their end of life. It addresses customer-specific projects as per the requested requirements of the customer. Other capital investments covered by the TDP include the telecommunications network, real estate, information technology (IT)/ operational technology (OT) and production equipment such as the vehicle fleet and trade tools.

17.3 NTCSA commitment to TDP delivery

NTCSA analysis indicates that the transmission network would need to be augmented by approximately 14 200km of extra-high-voltage lines and 170 transformers to bring on board 105 865 MVA of transformer capacity by 2032. NTCSA is placing a strong focus on the implementation of projects over the next five years and has implemented various strategies for the step-change performance required to deliver the infrastructure program. Strategic and operational structures have been set up to monitor, support and ensure successful delivery. A Programme Management Office has been established to accelerate the TDP. Established committees are used to fast-track the implementation of the key initiatives that will increase capacity to deliver the TDP.

NTCSA has identified two priority programs to accelerate the delivery of the infrastructure namely Additional Transformer (13GW) and Expedited Projects (24GW) consisting of 47 projects that will unlock 37GW grid connection by 2033. Over and above the 37GW priority projects program, NTCSA is developing approximately 193 expansion projects. These projects are at different stages of implementation in terms of design, procurement, and construction. 54 Expansion projects are in the procurement and execution phase, which will deliver 1230km of transmission lines, 16 790MVA and over 20000MW of grid connection capacity.

18 Understanding debt owed to Eskom

18.1 Customer payment levles and overdue debt impacted mainly by Municipal debt levels

Gross arrear debt is currently projected at R74bn in FY2024 whilst year-on-year growth is R15.9bn with Metros contributing R4.7bn and non-Metros R11.3bn. The average payment level for all customers, over the past 12 months was 94.9% but Municipalities were at 88.8%. Although municipal debt has significantly grown some municipalities are settling their debt. Although Metros have increased their payments, a significant amount is still outstanding. The cumulative metro overdue debt increased from R141m at the end of March 2022, to R1 783m at the end of March 2023 and is at R6 446m at the end of March 2024. However, late payments of R2.1bn were received from these metros after the March 2024 month-end, reducing the metro cumulative arrears from R6.4bn to R4.3bn.

18.2 Customer payment levels and overdue debt

The projected FY2025 total payment level of 95.0% is projected to worsen to 91.7% by FY2028, impacted by the annual non-payment including interest growth. Excluding interest, the total payment level is projected to marginally decrease from 95.9% in FY2025 to 94.3% in FY2028. The key contributors to the debt burden are municipalities, whose component of the projected overdue debt increases significantly. Without a meaningful and effective urgent intervention, the cumulative municipal debt is projected to increase to approximately 35% of the total allowable revenue being applied for by FY 2028 and approximately 45% by FY 2030. This indicates that the initiatives to arrest the debt are not effective and require significantly more attention that addresses the underlying root causes. It is evident that this trajectory cannot be allowed to continue. The impact on other consumers and the ability for Eskom to provide a service is being severely hampered. The extent of the challenge is demonstrated in the tables below.

TABLE 32 : SUMMARY OF PAYMENT LEVELS

Payment Level %	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Non Munics	99.5%	99.6%	99.8%	99.7%	99.7%	99.8%	99.8%	99.8%
Munics	89.9%	89.1%	89.6%	87.4%	84.3%	82.0%	81.4%	79.9%
Total Payment level %	**95.0%**	**94.8%**	**95.0%**	**94.0%**	**92.8%**	**91.7%**	**91.3%**	**90.6%**
Total Payment level % - Excluding Interest	**96.3%**	**95.6%**	**95.9%**	**95.4%**	**94.8%**	**94.3%**	**94.7%**	**94.8%**

The municipal overdue debt is projected to increase over the MYPD 6 application period from an annual capital growth of R13 870m in FY2025 to an annual capital growth of R28 710m at the end of FY2028, assuming the current trajectory of non-payment will continue; and limited benefit to be derived from the existing debt management levers including the municipal debt relief programme. See table below.

TABLE 33: SUMMARY OF OVERDUE DEBT

Overdue Debt R'm	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Top Customers	456	357	703	726	750	773	796	819
Other Large Power Users (LPU)	555	689	429	497	564	631	698	765
Other Small Power Users (SPU)	1 707	1 930	1 898	1 982	2 065	2 148	2 232	2 315
Soweto (SPU)	2 230	2 191	1 725	1 231	933	631	269	94
Non-munics	**4 949**	**5 167**	**4 756**	**4 436**	**4 311**	**4 184**	**3 995**	**3 993**
Municipalities	58 512	74 512	91 345	114 036	144 996	187 123	235 853	294 485
Total cumulative overdue debt	**63 461**	**79 679**	**96 101**	**118 472**	**149 307**	**191 306**	**239 848**	**298 479**

Overdue Debt - Municipalities R'm	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Cumulative opening balance		58 512						
New Interest raised	3 647	2 200	2 963	5 261	8 690	13 417	20 020	27 339
New Capital debt	10 111	13 800	13 870	17 430	22 270	28 710	28 710	31 294
Total annual overdue debt growth	**13 758**	**16 000**	**16 833**	**22 691**	**30 960**	**42 127**	**48 730**	**58 633**
Municipalities - Cumulative closing balance	58 512	74 512	91 345	114 036	144 996	187 123	235 853	294 485

18.3 Measure to address Municipal debt levels – NT debt relief programme

In the National Budget Speech on 22 February 2023, the Minister of Finance announced Government's municipal debt relief plans to address the arrear debt, subject to certain conditions. NT published Budget Circular No. 123 on 3 March 2023 and Budget Circular No. 124 on 31 March 2023, which provide further detail on the municipal debt relief plan, the application process for municipalities and the related conditions. The MFMA Circular No.124, lists elements and stipulations of this arrangement such as debt write off, resolving non-payment, prepaid metering and municipal revenue enhancement initiatives resulting in debt write-offs by Eskom. Eskom is to write-off the municipal debt over three years, from 01 April 2024 to post 01 April 2026, subject to the municipality's compliance with the conditions. This is illustrated in the figure below.

FIGURE 30: TIMELINE OF MUNICIPAL DEBT WRITE-OFF ONCE NT CONDITIONS ARE COMPLIED WITH

71 Applications have been approved by National Treasury for the National Treasury Debt Relief Programme. including 6 approved with additional conditions. These 71 Municipalities represent 95% of the Overdue Debt at 31 March 2023 and represent the most significant contributors to the R11.3 Billion non–Metro FY24 growth.

The following are the key observations:

- Six months into the programme, 24 Municipalities have shown positive moves towards reform. Note however, that many have joined the programme late and may have only a few months history of compliance.
- The concern is around Municipalities that have demonstrated their inability to pay their current accounts to remain on the programme. Attending to this would require National Treasury and other government departments to support the Municipalities to rectify the breach of National Treasury conditions.
- Delays in settling the new debt growth will result in additional interest on the new debt.

- 41 Breach notifications have been issued and 7 Municipalities have received notice from National Treasury regarding their termination from the programme.

It is submitted that this approach does not seem to be achieving the desired result. The debt burden continues to increase. Further, stricter interventions are required where the ability to pay the Eskom debt is prioritised. Where it is not possible, the underlying factors must be addressed. These underlying factors at local Government level ned to be addressed holistically. It is now time for bolder and more innovative solutions that allows municipalities to move to the right path.

18.4 Measures to address Metro debt levels

Distribution's risk mitigation for metro debt include:

- Continuous monitoring metro account payment patterns
- Metros are contacted five days before the due date to confirm payments
- Working with Eskom Treasury for updates on planned payments
- Proactive pursuit of metros non-adherence to contractual terms
- Expediting requests for payment extensions
- Continued consultations with metros on billing dates and payment terms
- Regular engagement and maintaining open communication channels
- Engaging metros and close monitoring of metro payments by Distribution's Clusters General Managers

18.5 Measures to address debt of other customers

Top Customers, other LPU and other SPU have good payment record. However, due to the adverse market conditions, the risk of non-payment by these customers exists and can have a significant impact even if only one of the large customers defaults. Small impairment values have been provided for Top Customers, other LPU and other SPU over the MYPD 6 period to cater for the related risk.

The conversion of post-paid (conventional) meters to prepaid has assisted with reducing non-payment in Soweto. This is supported by continued credit management enforcement for those remaining on post-paid.

18.6 Additional strategies to mitigate against the increase in impairments

To limit the growth of bad debt in the cost base, Distribution has adopted an approach to limit debt growth whilst enabling electricity sales and includes:

- **NT debt relief:** Distribution is to write off the municipal debt over three years subject to the municipality's compliance with the conditions.
- **Continuous review and enhancement of credit management policies processes:** Distributions's debt and credit management policies, processes and strategies are reviewed regularly to ensure the robust application of our credit controls to minimise the impact of escalating debt
- **Prepaid sales:** Out of Distribution's customer base of 7.2 million (March 2024), there are 6.9 million prepaid customers (96%). The strategy is to continue to offer new customers the prepaid option and convert existing post-paid customers to prepayment. High-risk customers have been identified in all provinces and are converted to prepayment. The conversion process is in progress. Several large power accounts are also on a payment-in-advance option, to reduce the debt risk to Distribution. Prepayment for large power supplies is being investigated and will be supported through smart metering
- **Deposits / Security:** Ensuring an increase in deposits and securities to mitigate future risk by customers identified as potential high-risk defaulters. The process to ensure adequate account security across all customer segments will be managed over time to balance this requirement and the unintended consequence of an increase in overdue debt
- **Innovation:** Distribution has successfully piloted revenue collection for two municipalities. This included the replacement of meters in the municipality, maintenance as well as billing of large power customers. The results indicated a reduction in overall municipal losses and an increased cash for the municipality. Different operating models are being investigated to ensure viability and sustainability in the future electricity industry
- **Municipal revenue enhancement initiatives:** The National Treasury continues to implement initiatives to address weaknesses in revenue management in municipalities. These initiatives include setting cost-reflective tariffs, developing proper budget policies to facilitate revenue enhancement and ensuring completeness of revenue. These initiatives are supported by the Municipal Revenue Management Improvement Programme (MFIP) technical advisors. Furthermore, the National Treasury advised that a transversal tender for the smart meter solution (smart prepaid meters) will be issued to assist municipalities generate cash pre-service, rather than, post-service. Some of

these elements have been linked to the National Treasury Municipal Debt Relief Programme

- The service delivery proposals make provision for different working arrangements with municipalities as agreed in the service delivery framework. In extreme cases, it may even be requested that Distribution take over the electricity service delivery within financially distressed municipalities. The consultative activities have included and will continue to include engagements with the respective municipal executives.
- Intergovernmental provincial meetings with all the relevant stakeholders
- Regular National Governmental meetings including Active Partnering
- Regular engagements with the National Treasury on Circular 124

19 Outcome of economic impact studies

An independent study was commissioned to ascertain the impact of the electricity price path over the MYPD 5 period on the macroeconomic variables. The objective was to model the trade-offs of the different approaches as to who pays and when they do so, providing a fully informed consideration of the potential economic impacts of various pricing paths over the short-to-medium term. It should be noted that this study was undertaken during the MYPD 5 revenue application. The principles are still applicable for the MYPD 6 application.

To ascertain the impact of price adjustments the following four scenarios were modelled.

- **Eskom's high-price, quick recovery toward cost reflectivity scenario**. Some key macroeconomic variables, such as GDP and investment, deteriorate relative to the baseline in the first year following the large electricity price increase. However, macroeconomic variables generally perform better than the baseline in the medium term as the impact of the price shocks are offset by the improved credit rating. Modelling Eskom revenue shortfalls by means of government debt financing, the government deficit is significantly reduced by R110.48 billion by 2026.
- **Eskom's MYPD5 Application**. With the increase in electricity prices almost eliminating the annual revenue shortfall at Eskom by FY2026 relative to the baseline. This again follows from the fact that there is much less need for government subsidies (as well as the assumption that government expenditure remains on the baseline path). GDP deteriorates slightly relative to the baseline in the first year following the electricity price increase, but all macroeconomic variables beside inflation perform better than the baseline in the medium term as the impact of the price shocks are offset by the improved credit rating.
- **Eskom's low-price scenario**. With electricity prices only slightly higher than the baseline, Eskom's annual revenue shortfall decreases marginally. The government deficit thereby also reduces by R29.39 billion by FY2026 relative to the baseline. Whilst a significant annual revenue shortfall is still expected, it will be slightly less than in the baseline price (where full economic costs are also not covered by tariff levels, but less severely so). Since there is not a significant deviation in the baseline electricity price path, and by implication financial stability of the SOE, under this scenario, no further changes relative to the baseline credit rating are expected. Most key macroeconomic and fiscal variables remain below baseline projections over the simulation period.
- **CPI-linked, very low-price scenario**. With significantly lower electricity prices than in the baseline, the annual revenue shortfall at Eskom widens and the government deficit

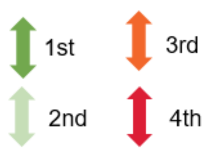
similarly increases by R81.7 billion relative to the baseline. This follows from the more extensive need for government subsidies to cover Eskom's shortfall. A significant annual revenue shortfall, worsening Eskom's financial position and further destabilising the country's overall fiscal outlook, results in an expected credit rating downgrade. Whilst consumers benefit from the cheaper price of electricity and lower inflation more generally, this is offset on a macroeconomic and fiscal level by the effects of increased budget deficits, higher debt-servicing costs, lower employment, lower household consumption spending, less government tax revenue and less investment.

- The ranking of the four tariff scenarios in terms of the outcomes of each of the modelled macroeconomic variables is shown in the figure below. The MYPD5 Application scenario performs best on the majority of the variables of interest (five of the eight). Relative to the other price path scenarios modelled, this suggests that the scenario is the optimal mix between achieving a sustainable electricity price path toward cost reflectivity and considering the short-run impacts on consumers and the broader economy.

FIGURE 31: RANKING OF FOUR TARIFF SCENARIOS

Scenarios	Macroeconomic indicators (cumulative % deviation from Baseline from 2022 to 2026)					Financing indicators (cumulative deviation from Baseline from 2022 to 2026)		
	GDP	Employment	Inflation	Investment	Household consumption	Public sector deficit (R bn)	Current account balance (R bn)	Tax revenue (% change)
High-price	0.29%	0.03%	0.80%	4.06%	0.33%	-R110.48 bn	-R137.00 bn	4.56%
MYPD 5 Application	0.64%	0.25%	0.85%	6.95%	0.82%	-R110.25 bn	-R255.47 bn	5.10%
Low-price	-0.14%	-0.16%	0.14%	-0.54%	-0.23%	-R29.39 bn	R28.39 bn	0.91%
Inflation-linked	-0.81%	-0.43%	-0.15%	-6.84%	-1.13%	R81.71 bn	R274.84	-3.96%

Legend for ordinal ranking of scenarios



In large part as a consequence of historical under-pricing and under-investment, Eskom's current operational and financial challenges are placing a significant strain on the country's economy. Insufficient generation capacity and short-term supply shortages have seen record-levels of loadshedding implemented for each subsequent year from 2019 to 2021. Based on CSIR upper-bound estimates of annual loadshedding and the official Cost-of-

Unserved Energy estimate of R87.50 per kWh94, back-of-the-envelope estimates suggest that loadshedding could have cost the economy up to R118 billion in 2019 – or just over 2% of the value of total GDP. By 2021, and using the same arithmetic, the cost of loadshedding has almost doubled, increasing to R214.8 billion in nominal terms.

Similarly, credit ratings agencies cite fiscal deterioration due to Eskom's debt levels as the country's main credit risk. Eskom's debt alone amounted to 15% of total government debt in 2019 (or equivalent to the value of 9% of the country's GDP).

Across the majority (six out of eight) of the macro-economic and fiscal indicators, the economy is decisively better off over the medium term if prices are set such that they reach cost-reflective levels over the MYPD5 period. The only metric on which consumers are marginally worse off under tariffs approaching cost-reflective levels is inflation – but this is more than offset by increases in GDP growth, employment, investment levels and household consumption spending.

Among the paths to cost-reflectivity over the MYPD5 period, the smoothed pricing path proposed under Eskom's MYPD5 application is preferable to one where price-increases are front-loaded to achieve cost-reflectivity as soon as possible. The NERSA revenue decision did not allow for the expectation in the MYPD 5 to be met. Thus, the MYPD 6 application still has the same impact. In a dynamic sense, the general pattern is one of "short term pain for long term gain." Whilst most metrics experience some immediate, adverse shock in the first-year or two as the economy adjusts to tariffs under the cost-reflective pricing paths, the aggregate state of the economy over a five-year period improves as Eskom's financial position and the country's credit rating improves.

These results are consistent with the widespread acceptance that prices play a key role in efficient resource allocation. Economic theory suggests that in a context of scarce resources, prices play a key signalling role to both consumers and producers, informing their decision-making and so facilitating the optimal resource allocation.

Price elasticity studies – key outcomes

A frequent and robust estimation of the price elasticity of electricity demand is a helpful tool to understand the consequences of price changes on consumer demand and the revenue that a utility can expect to generate. As Eskom's total revenue (R) is its average price per unit of electricity sales (P) multiplied by total consumption (Qd) (or R= P x Qd), this means that when demand is inelastic (elastic), a price increase will lead to an increase (decrease) in revenue from sales, all else held constant.

TABLE 34: INTERPRETING PRICE ELASTICITIES

Price elasticity (Ɛ)	Interpretation	Revenue implication
Elastic (|Ɛ|>1)	% change in Q_d greater than % change in P	**Revenue decreases with price increases** (% increase in P more than offset by % decrease in Q_d)
Inelastic (0≤|Ɛ|<1)	% change in Q_d less than % change in P	**Revenue increases with price increases** (% increase in P causes a smaller % decrease in Q_d)

The elasticity estimates for the respective sectors are as follows:

- **Industrial**: The price elasticity is negative and significant, but below 1 – indicating that demand is price inelastic. A 1% increase in prices is associated with a 0.254% decrease in demand for industrial consumers. We find no evidence to suggest that the price elasticity changed before and after the assumed structural break from 2008. The income elasticity is positive and significant but inelastic. A 1% increase in the economic output sees a 0.828% increase in electricity demand.
- **Mining**: Mining customers also price inelastic: a 1% increase in prices is associated with a 0.107% decrease in demand. We find evidence that the elasticity marginally decreases in absolute terms after the break. Electricity is income inelastic, with a 1% increase in economic output associated with a 0.5% increase in demand.
- **Rail:** As with other sectors, demand is price inelastic. A 1% increase in prices is associated with a 0.445% decrease in demand. Again, there is evidence that the elasticity may have marginally decreased after 2008. Rail is an outlier in the sense that its income elasticity is greater than 1, suggesting a relatively elastic response to output changes (measured here as annual rail freight tonnages hauled). A 1% increase in the economic output is associated with a 1.455% increase in demand when all other things remain unchanged.
- **Bulk sales to municipalities**: Demand is also price inelastic for municipal distributors' bulk electricity purchases. A 1% increase in Eskom's prices is associated with a 0.218 % decrease in bulk demand. Note that this is not the elasticity to end consumers, however, which would be determined by a range of other additional factors (like municipal costs in

distributing electricity to their end-consumers, including technical and non-technical distribution losses, as well as any additional municipal margins on-top of bulk purchases from Eskom). We find some evidence that the elasticity may be marginally lower in absolute terms after 2008. Municipal demand is also income inelastic, with a 1% increase in national household disposable income associated with a 0.243% increase in bulk electricity purchases from municipalities when all other things remain unchanged.

- **Eskom's direct Residential customers** are price inelastic over the period from 2010 - 2020, with a 1% increase in prices associated with a 0.614% decrease in demand. In contrast, their demand is income elastic, with a 1% increase in household disposable income associated with a 1.014% increase in demand. However, it is not possible to draw conclusions from the elasticity estimates for this subset of Residential customers to the broader Residential sector. The predominant share of Residential customer demand (72%) is supplied by municipal distributors, whose prices vary significantly and can be much higher per kWh than those faced by the equivalent Eskom customer.
- **For the aggregate demand from the national grid**, we find that the economy overall is price inelastic over the period from 1990 to 2020. A 1% increase in prices is associated with a 0.144% decrease in demand. Although the price elasticity of demand over the entire analysis period is inelastic, we also investigate the time-varying nature of the elasticity and find that elasticities have changed over time, especially in the period immediately after 2008. Shortly after the first significant real price increases and rounds of loadshedding, the price elasticity peaks at -0.37 in 2009. Since then, the price elasticity has stabilised in a range between -0.15 and -0.10 in the decade from 2011.

19.1 What does electricity cost around the world?

The reason to consider price comparisons is twofold. Firstly, for the industrial sector, the electricity price will contribute to the decision to invest. Thus international comparisons, will be important in guiding the decision to be made. Secondly, it can be assumed that in many developed countries, and certain developing countries, the price of electricity is at a level that allows entities to recover the efficient cost of producing the electricity. Thus this provides a benchmark of comparison. It is recognised that technologies, terrains, proximity, level of subsidies, cross-subsidies and other factors may differ. These factors need to be taken into consideration. It is also important to take into consideration which tariffs are being compared – could be industrial, residential, the average prices or any other tariff. However, the comparisons are provided to be in a position to place Eskom's tariffs into appropriate context.

19.1.1 International Energy Agency analysis

Recent data available from the International Energy Agency (IEA) for comparison provides a similar picture of the relative affordability of Eskom's electricity tariffs as those presented by other studies discussed above. Eskom's prices for 2021/22 are placed in relation to an international comparison conducted annually by the UK National Statistics Department of Business, Energy & Industrial Strategy. This compares electricity tariffs for industrial and domestic customers for the fifteen major EU countries and a sample of other countries across the IEA. The IEA data collected by UK National Statistics is converted to US cents/kWh based on exchange rate data collected by UK National Statistics and benchmarked against Eskom's 2021/22 tariff data (converted to US cents/kWh) as published on its website and the 2021 Annual Report. This dataset is used as it is updated and maintained by a credible source (UK National Statistics) on a quarterly basis.

The Figures below illustrate that relative to the sample of IEA benchmarked in this study, Eskom's prices for industrial and domestic customers are amongst the lowest in the sample, with only Norway's industrial electricity price being lower than Eskom's.

FIGURE 32: ESKOM AVERAGE INDUSTRIAL AND MINING PRICES VS IEA INDUSTRIAL PRICES (MARCH 2023)

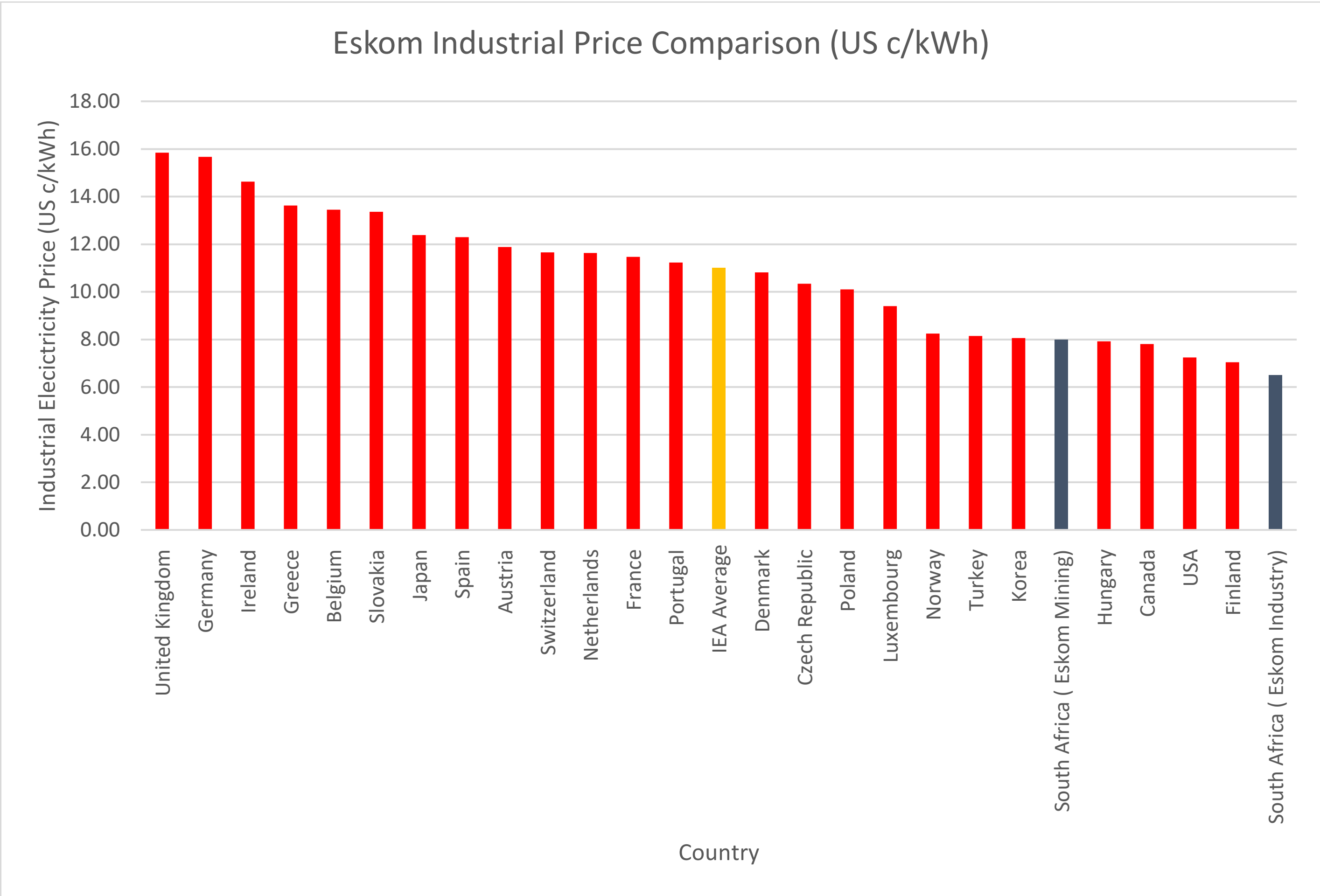
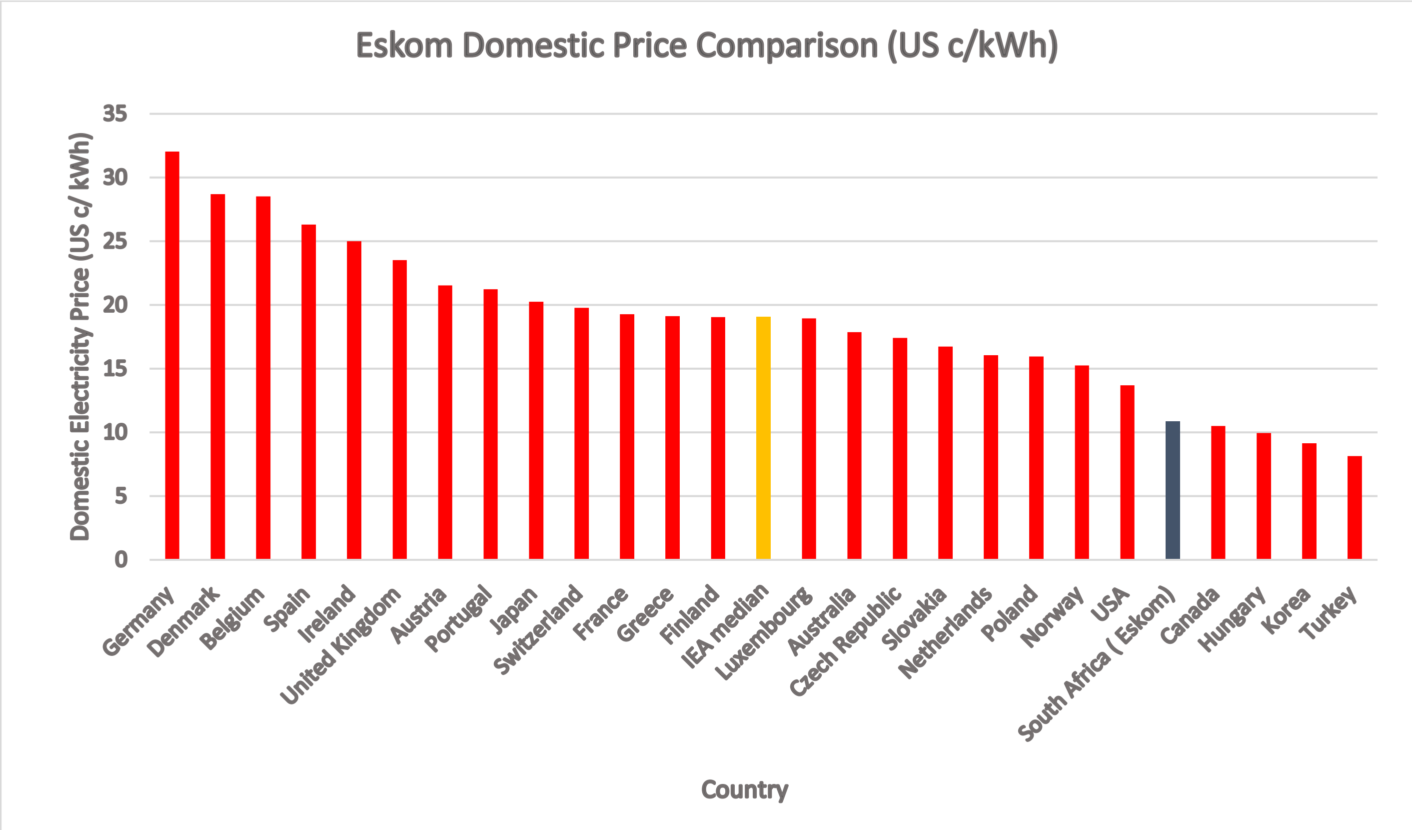


FIGURE 33: ESKOM AVERAGE DOMESTIC PRICES VS IEA DOMESTIC PRICES (MARCH 2023)



20 National Treasury and SALGA responses

20.1 Summary of key responses provided to comments by National Treasury as part of consultation process for the MYPD6 revenue application

20.1.1 Inadequate tariffs have impacted Eskom's ability to operate

National Treasury recognises Eskom has been dependent on borrowings and shareholder support to remain a going concern and the missing link has been the tariffs that cover the efficiently incurred costs and allow for a fair return on assets. There continues to be a need to strike a delicate balance between the negative socio-economic impacts of the increases, especially in the context of the current global economic environment, whilst simultaneously ensuring a financially sustainable electricity industry including Eskom.

Eskom continues to make every effort to migrate towards a cost reflective tariff that covers efficient costs and a fair return. Eskom recognizes that this cannot be achieved in this application and thus the migration continues. This is mainly to ease the socio-economic impact on industry and vulnerable citizens as alluded to in the above-mentioned comments.

20.1.2 Sales volumes need to be addressed

While the National Treasury generally supports the move towards cost reflectivity, it is concerned that the continued reliance on tariff increases as a source of revenue growth whilst not addressing sales volume growth presents a considerable sustainability risk for the business. Given recent developments in the industry such as the lifting of the licensing threshold, the introduction of incentives for rooftop solar PV, and the resulting impact on demand, it may be prudent for Eskom to take this into account, however, it is currently not explicit in the discussion. It's not clear what the current sales forecast scenario assumes for this type of generation, which is anticipated to continue growing. This should be included directly in the sales forecast discussion, but the demand projections currently seem to be informed only by the GDP outlook.

Eskom supports that increase in sales would be beneficial. However, it needs to be noted the shortfall in revenue will require a significant increase in sales that are completely dependent on economic development in the country. With respect to demand or sales growth and its drivers, the dominant factors and drivers of electricity demand and thus sales volume have been overall national economic growth; commodity prices; structural changes to the economy (e.g. reduction of mining and manufacturing and growth in services), technological changes, population growth, weather patterns, electricity intensity levels. The policy drivers of the country on investment choices have been found to be paramount. From an electricity perspective, customers require a long-term price path (price stability), reliability of supply (availability), a reliable supply, and competitive pricing (level). Other operational factors that impact sales of electricity in South Africa include

- Low economic growth internationally – no markets for products (stockpiling).
- Commodity market volatility, particularly in gold, platinum, and ferrochrome.
- Rapid evolution of technology development in the energy industry
- Some of the large power user customers having been liquidated or applied for business rescue due to financial vulnerability and low competitiveness in their sectors
- Some industries that have shut down operations and relocated to Asia due to incentives offered in those countries
- Voluntary contribution to the energy reduction strategies during load shedding accelerated energy efficiency and self-reliance.
- Opting to export un-beneficiated ore due to high market prices.
- Labour costs and relationships
- Reliability and cost of logistics

Eskom has a role to play in contributing to the reliability of supply. Key constraints in this arena, that the industry is still grappling with include the implementation of policy decisions timeously, financial constraints – which results in having to make difficult choices and ensuring the availability of skills. This has been defined as a key focus area for Eskom and details are included in this submission.

The projections for sales forecasts have included the impact of further roof-top solar PV and the lifting of the licensing threshold. This has thus resulted in a decreasing trajectory for the sales forecast.

National Treasury requests further clarification on increase in NPAs

In the FY2026, an additional 10 NPAs were included in the revenue application. These were concluded after the FY2025 revenue decision was made. These NPAs were approved by NERSA in accordance with the frameworks approved by the DMRE. The DMRE issued an Interim Long-term Framework for NPAs in 2020, in terms of the EPP, with its primary objective being to provide qualifying industries with a globally competitive electricity tariff to mitigate against the loss of baseload electricity sales and negative impact on other customers and the economy. NPAs are structured to ensure the global competitiveness of the sector from an electricity price perspective. Implementation of a NPA, once approved by NERSA, will result in sustaining baseload sales volumes albeit at lower revenue levels. Eskom has implemented NPAs with customers in the aluminium, ferrochrome, and silicon carbide sectors totaling sales of ~ 23 TWh per annum. South Africa is better off with these customers in the sales base as the NPA structure ensures the relevant variable costs of electricity supply are covered by the tariff and a positive contribution is made to the fixed cost. The typically flatter time-of-use and no seasonal differentiated NPA tariff could result in even usage throughout the year with a likely increase in sales which would partly offset the differential between the NPA tariff and standard tariff. In the absence of a NPA, the sustainability of these industries is in question which could result in potential cut-back in production or closure. This would result in additional upward electricity price pressure on the remainder of the customer base than would otherwise be the case due to loss of contributions to fixed costs.

20.1.3 Impact on municipalities and their ability to address their debt to Eskom

The growing municipal debt is highlighted as a key challenge. Despite interventions, municipal debt continues to rise, indicating a need for more effective solutions. The link between high tariffs and increasing municipal debt underscores the adverse impact of Eskom's financial strategies on local government finances. Income and expenditure play a critical role in assessing the capacity of municipalities to deliver services. Many municipalities generally have multiple income streams, but electricity is a significant contributing factor. Municipalities purchase electricity in bulk and then resell the power to homes and businesses. So, the collection of revenue for services rendered is important for the financial viability and sustainability of municipalities. The proposed tariff increases of approximately 43.5% for municipalities for the first year of MYPD6 may increase non-payment rates and the arrear debt owed to Eskom resulting in lower revenues for Eskom. There is a risk that municipalities may look towards cheaper alternative electricity sources to reduce operating costs.

Eskom acknowledges that the Municipal debt owed to Eskom needs to be addressed. It is submitted that the interventions put in place are not yielding the results that were envisaged. It is thus necessary for the Government, NERSA, Eskom, SALGA and Municipalities to work together to find viable solutions that address the key underlying factors that inhibit the payment for services received. It is also acknowledged that certain Municipalities do make payments. Thus further detailed analysis is required. It has been illustrated that if further interventions are not put in place, an untenable situation will result in the next few years. The focus is for Municipalities to pay for the service they receive. The expenditure component has to include the payment for the service provided by Eskom. NERSA approves tariffs for Municipalities that allows them to recover the input costs that are payable to Eskom. It is understood that in addition to tariffs approved by NERSA, many municipalities also impose surcharges. This is likely to increase the price of electricity paid by these municipal customers – which could apply further pressure on customers to pay for the service being provided. It would be beneficial for the country overall, if viable alternative sources of energy are successfully sourced. This may result in decreasing the debt burden on Eskom.

20.1.4 NT Debt support requires cost reflective tariffs to be addressed

The National Treasury recognizes that to return Eskom to financial sustainability and to ensure the success of this solution, certainty of tariff is crucial. The achievement of sufficient revenue is essential in determining the levels of investment in the capital expenditure programme and maintenance required to improve plant performance as well as the financial health of Eskom. Therefore, taking over the debt without addressing the tariffs will not return Eskom to a sound financial position. Hence, the National Treasury's view is that it is crucial to emphasise the important role that NERSA plays in making tariff determinations that will respond to Eskom's future financial sustainability. It is also important to emphasise the importance of correctly implementing the revenue methodology without Eskom having to revert to the Courts. Approving cost-reflective tariffs will enable Eskom to effectively address its capital structure and increase investor confidence. Eskom has been dependent on borrowings and shareholder support in the recent past, to remain a going concern, partly due to tariffs that have not been sufficient to cover the efficiently incurred costs and allow for a fair return on assets. This negatively impacts Eskom's ability to carry out its operations and honour its obligations and this threatens its future financial sustainability. Therefore, there is an urgent need for MYPD methodology to be applied consistently to provide certainty in the electricity sector, as well as provide revenue certainty for Eskom and the fiscus.

Eskom is in agreement and hopes that the MYPD methodology will be adhered to by NERSA when it makes its revenue determination.

20.1.5 Eskom to reconsider the level of ROA

In this revenue application, Eskom has applied the NERSA MYPD methodology with a phasing-in of ROA. Thus, the National Treasury notes that Eskom's decision to phase in the ROA implies that the MYPD methodology is not being applied in its correct form. Eskom stated that the phased implementation of the ROA is to prevent a shock to the eventual price increase. However, the National Treasury believes that the decision to phase in the ROA should be left to NERSA.

Eskom notes the National Treasury contribution. NERSA will have an opportunity to implement its methodology to the fullest with regards to ROA when it makes its decision. Eskom has modelled the impact of applying for the ROA as determined by NERSA during the MYPD 5 period. It results in almost three times the ROA for FY 2026 and double for FY 2027 and 2028. This will also have a phenomenal impact on the price of electricity in those years. Eskom understands that a delicate balance needs to be struck. That is precisely the reason that in the MYPD 6 application, Eskom continues to request a ROA that migrates towards a cost reflective level. It needs to be noted that the ROA is determined on the depreciated replacement value of the assets. In this application a focus is on applying for efficient costs in accordance with the MYPD methodology. Detailed motivations are provided for each aspect of the revenue application. NERSA will undertake its own benchmark analysis before making a determination.

20.1.6 Employee benefit costs

As evident by previous decisions, Eskom has consistently spent above NERSA's determinations and has been unable to recoup excess costs. Therefore, although the costs are stabilizing, it is expected that Eskom will move towards managing its employee benefit costs in line with NERSA's decision. Also, Eskom needs to ensure that these costs are contained to NERSA determination, as over-expenditure cannot be claimed later through RCAs according to the MYPD methodology.

It needs to be clarified that the RCA process allows for variances in employee benefit costs and operating costs to be applied for. Inadequate decisions made in the past have a severe impact on the application years. Due to having to correct for the past decision, it has been found that the first year of the three-year cycle needs to allow for a correction to the reality in terms of the MYPD methodology. It is quite clear that NERSA does not adequately consider the latest actuals, followed by the subsequent projections, when it analyses the revenue application being made. It is acknowledged that these actuals and projections need to be analysed in terms of NERSA methodologies and frameworks, especially the prudency framework to provide a sense of what has transpired and the best projections of the immediate future. It is unfortunate that NERSA continues to make revenue decisions based on its previous decisions (albeit inadequate) – and does not analyse the latest reality. In addition, the adjustments made by NERSA in its RCA decisions are not at all considered when it makes a subsequent revenue decision. It is unfortunate that this oversight / error continues to be made.

As an example, for employee benefit costs, Section 10.4.9 of the MYPD methodology refers to "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" – thus, Eskom provides a motivation based on the latest actuals. However, NERSA bases its decision on a previous decision it made – and allows an increase for employee benefit costs on a previous decision. This ends up in a continuous incorrect spiral – since the basis is incorrect.

In terms of the NERSA guideline on prudency, costs need to be assessed for prudency. They need to be evaluated on the merits by the Energy Regulator. A simple application of an inflation increase does not indicate that the costs were evaluated for prudency, efficiency and reasonableness. Prudency is linked to the MYPD Methodology as follows:

“5.2.1.5 Although prudency is not a term used in the ERA, prudency is directly linked to efficiency, and it is international best practice for regulators to assess the prudency of expenditure. Efficient Licensees will make prudent decisions and prudent decisions will make a licensee efficient, which is why the assessment of prudency is included in the MYPD Methodology. The MYPD Methodology requires that the licensee exercise prudence in all its regulated activities. This is in accordance with the requirements of Policy Position 1 of the EPP.”

It needs to be noted that the majority of Eskom’s costs are based on underlying contractual obligations. These contacting processes are governed by a myriad of policy and legislative requirements. These include ensuring compliance to the Public Finance Management Act (PFMA), the various procurement legislations and policy as well as meeting National Treasury requirements. This demonstrates the rigour and thoroughness that Eskom has to adhere to before finalising any contract. In addition, compliance is monitored by many authorities including the National Treasury. NERSA would need to take this into consideration when determining the prudency of Eskom’s costs.

The following NERSA statements in previous decisions illustrate that NERSA is not applying its methodologies. “Eskom’s expenditure is not in line with NERSA’s decision. From the 2013/14 actuals to the 2019/20 projections, Eskom has consistently spent more than the NERSA decision. Eskom’s reasons for the over-expenditure are that the assumptions used in determining other costs do not use NERSA’s decision as a base. The assumptions used considered the economic conditions at the time and other elements that influence other costs. This reason is considered unacceptable, as it does not take into account the Energy Regulator’s decision.”

In addition, the High Court, in its judgement on the review by Eskom of NERSA’s FY2019 revenue decision, found NERSA’s approach to employee benefit costs to be irrational. The summary of the court judgement on this matter is that NERSA cannot use the employee numbers ratio to sales volume in 2007 as a basis for determining employee benefit costs. The Court clarified that as an example, employees working in the construction of power stations, will not directly contribute to sales volume. However, in all subsequent decisions since the FY2019 decision, NERSA continues to make an inflation adjustment to the decisions judged to be irrational by the High Court. This process has continued for six financial years. The direct impact of such an incorrect approach requires adjustments to be made.

20.1.7 Eskom Generation performance

> National Treasury notes that the projection of the Generation Technical Performance indicators, which includes the energy availability factor (EAF) should be updated. Given the recent improvements in the EAF and the revised winter outlook projecting less load shedding, Eskom needs to make it clear whether the current trajectory is still relevant and in line with improved performance.

Eskom confirms that the assumption made Eskom's Generation Technical Performance was relevant at the time the application was being prepared. As has been done in the past, Eskom will share updates on any further developments in key performance criteria, availability of IPPs, changes in sales forecast, etc prior to NERSA making its decision. NERSA can consider such developments when making a final decision. This has always been the case due to the long consultation period required for the revenue determination process.

20.1.8 Capital expenditure

> NT requires clarity as to whether the expenditure is reflective of the full requirement of the TDP or whether it is assumed that some component of the TDP will be undertaken by the private sector which is currently being pursued by Government.

For the application period, the capex assumption is that the full requirement of the TDP is included. Since details on alternative have not yet been finalised, they could not be included. In the event that further clarity is provided prior to NERSA making a decision. this can be provided to them to guide the decision-making. The recovery of the funding provided by the private sector will most likely still be the end consumer.

20.1.9 Carbon tax

In the 2024 Budget, the government announced that a carbon tax discussion paper on the phase 2 carbon tax design from 2026 will be published for public comment and stakeholder consultation later in 2024. The paper will set out proposals for adjusting the tax-free allowance/s under the carbon tax and revenue recycling measures. It is noted that the revenue application for 2026/27 and 2027/28 will be directly impacted by the phase 2 carbon tax proposals.

Therefore, the National Treasury encourages Eskom to fully participate in the public consultation process on the carbon tax discussion paper. To provide policy certainty and ensure that the carbon tax design from 2026 after the public consultations is considered in the MYPD revenue application, alignment of the processes is crucial and National Treasury would welcome further discussions with Eskom to clarify the policy process.

The National Treasury notes Eskom's views expressed on the carbon offset allowance. However, there are opportunities for Eskom as part of its research, development, and innovation strategy and budget to develop and explore non-energy related carbon offset projects where credits generated can be sold to other companies subject to the carbon tax. Over time opportunities to scale up these initiatives and diversity in the Eskom business will emerge.

Eskom does not seem to be fully utilizing the tax-free allowances under the carbon tax as shown above. This is problematic as opportunities to lower its carbon tax liability and the required electricity price increases are not being considered by the entity, thus imposing an additional, unfair burden on consumers, particularly from 2026. Therefore, the National Treasury encourages Eskom to develop a strategy on how the tax-free allowances can be fully utilized as part of the revenue application.

Eskom has considered the relevant legislation and proposals at the time the application process was underway to arrive at an understanding of the carbon tax liability. Eskom will gladly participate in the process to further clarify the implications and how these are likely to reduce the burden on the end consumer. It is envisaged that further clarity will be provided during 2024 once the consultation process alluded to is undertaken by Government. These updates will be shared with NERSA before a final decision is made. Any further adjustments, as were done previously by NERSA could be included in the final decision.

20.1.10 Economic impact requires further analysis

National Treasury requests that further studies be undertaken to determine the impact on the economy.

These recommendations are noted and will be considered when further analysis is undertaken.

20.1.11 RCA liquidation in 2026 to be considered by NERSA

National Treasury raises concern about the liquidation of further RCA decisions in 2026 .

The regulatory environment makes provision for the differences between the decision and the actuals to be managed through the Regulatory Clearing Account (RCA). This is the mechanism that Eskom uses to manage the actual revenue compared to the NERSA decision. This is a globally accepted mechanism that forms part of the MYPD methodology, and it is envisaged that it will continue to be applied during the MYPD 6 period.

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20.1.12 Impact of policy changes and restructuring of electricity industry

National Treasury proposes further discussions on the policy changes impact of the restructuring of the electricity industry on tariffs. Concern raised that if streamlining does not occur, could result in higher tariffs.

This MYPD 6 revenue application has been prepared in accordance with the MYPD methodology as published by NERSA during October 2016. The NERSA revenue and tariff decisions will be implemented from 1 April 2025 for non-municipal customers and from 1 July 2025 for municipal customers. The key outcome of the MYPD revenue application process is to determine the average price of electricity to the end consumer. This is the same situation as for the FY2025. When the ERA amendment is implemented, changes will be guided by NERSA. In terms of the ERA amendment, NERSA is required to develop transitional arrangements to guide the industry participants. The manner in which these unfold will guide on the price impact. It is also envisaged that NERSA will consider the impact of the restructuring of the industry on the tariffs when undertaking the necessary transitional arrangements.

20.2 Summary of SALGA responses related to the MYPD 6 Revenue Application

20.2.1 Focus of MYPD 6 revenue application on ensuring electricity supply

The current version of the MYPD 6 is mainly driven by ensuring security of electricity supply without dealing much with issues of sustainability and affordability of such services. These other objectives are central to economic growth and prevention of death spiral to Municipal Business. It is felt that the price increase being applied for will impact affordability.

As acknowledged by SALGA, this revenue application is made in accordance with the EPP and ERA that allows Eskom to recover efficient costs and a fair return. It is submitted that the affordability of electricity continues to be considered in this revenue application by the migration of the ROA towards the WACC. Eskom has continued this journey from previous revenue applications and will not reach the WACC as determined by NERSA during the MYPD 5 period. This lowers the revenue application being applied for, when compared to fully applying the MYPD methodology. This is a migration towards the "user pay" principle, where consumers pay for the efficient cost of the service they receive. It has been demonstrated by economic impact studies undertaken that prices play a key role in efficient resource allocation. Economic theory suggests that in a context of scarce resources, prices play a key signalling role to both consumers and producers, informing their decision-making and so facilitating the optimal resource allocation. As reflected in Eskom's integrated report for FY 2023, the significant shortfall in NERSA decisions over more than a decade has resulted in the increase in Eskom's debt burden. In addition, further pressure has been exerted by the increasing municipal debt where certain municipalities have not kept up with their payment obligations. The outcome of the shortfall has been that difficult choices have to be made in continuing to provide electricity within the constraints of inadequate funding. It is understood that in addition to tariffs approved by NERSA, many municipalities also impose surcharges. This is likely to increase the price of electricity paid by these municipal customers.

It is recognised that when NERSA makes it ERTSA decision, it will consider the affordability subsidy adjustments that will contribute towards protecting the poor residential customers. In accordance with the requirements of the EPP, various other support mechanisms are considered for the poor residential customers. These include the electrification programme, free basic electricity and the inclining block tariff. When NERSA makes it's decision for Municipal tariffs, it ensures that the cost of purchasing electricity from Eskom is recovered.

20.2.2 Regulatory Asset Base components

SALGA proposes that work under construction and working capital should not be included in the determination of the RAB.

Eskom is required to comply with the MYPD methodology that requires their inclusion. This is also aligned with the EPP.

20.2.3 Clarification on energy requirements met by Eskom power stations and IPPs

Clarity is sought on energy assumed to be secured from Eskom power stations and IPPs. The volume of energy from IPPs has been ringfenced. Further understanding on energy from Eskom power stations is requested.

The details are provided in the outcome of the production plan. The assumed energy from coal-fired power stations, OCGTs, IPPs, etc to meet the demand is detailed.

20.2.4 Carbon tax

SALGA is of the opinion that the UN reports on the link between carbon dioxide emissions and global warming are untrue. It is proposed that any saving on payment of carbon tax liability in the earlier three quarters of FY 2026 be used to pay the liability in the last quarter of FY 2026

Eskom is required to meet all legislative requirements when a revenue application is being made. The introduction of the carbon tax liability from January 2026 is respected. Prior to then, carbon tax is not paid by Eskom, thus no savings can be accrued.

20.2.5 Arrear Debt and NT debt relief package implementation

It has been recommended that the growth in debt not be included in the revenue application. It is clarified that not all municipalities owe Eskom for electricity supplied to them and thus would be inequitable. Eskom is required to work towards the Municipal responses.

The comments are noted. It should be noted that the municipal debt is included in the context of the impact on Eskom's sustainability. There is great room for improvement of Eskom's and municipal sustainability, if the municipalities implemented the debt relief package. Eskom will make every effort to make the necessary adjustments.

20.2.6 Operating costs

> *SALGA has determined that operating costs increase by 50%. SALGA determined that other operating costs should not increase and decrease in the way that they did. SALGA indicates that coal costs should decrease since IPP costs are increasing.*

This analysis does not seem to be aligned with the Eskom application. Eskom has confirmed that Eskom's projected operating costs, over the period FY2024 (Q2 projections) to FY2028 have a CAGR of approximately 5.4%. The other operating costs see an increase in CAGR of 11.36% over the period. Meaningful comparisons could not be made to the NERSA decision for FY2025, due to decisions being made on the basis of previous decisions. NERSA has not provided any analysis for its previous decisions. For the sake of comparison, a CAGR of 14.5% is calculated from the NERSA FY2024 decision to FY2028 operating cost application. The coal costs are based on the outcome of the production plan and coal sourcing strategy.

20.2.7 Negotiated Pricing agreements

> *It is proposed that variances due to the implementation of NPAs should be funded by Government*

NERSA has made decisions to implement NPAs in accordance with the DMRE frameworks. These have been included in Eskom revenue applications. The DMRE has amended the short term negotiated pricing agreements (NPA) framework and developed an interim long term NPA framework in accordance with the requirements of the EPP. The Short-term NPAs have been specifically structured to provide opportunities to sustain existing businesses that are at risk of failure and permit others that have closed production capacity in recent years, owing to their inability to compete in their markets, to restart. The rationale for the interim long-term framework is to protect vulnerable sectors, improve relative sector competitiveness and attract investment in the long-term. These two frameworks will allow for the relevant vulnerable sectors, which are impacted by the price of electricity and meet the required criteria, to be supported to allow for further contribution to economic activity of the country.

20.2.8 Further regulatory clearing account implementation

> *Clarity is sought on further RCA implementation decisions*

Eskom is dependent on NERSA making decisions on whether further RCA balance decisions will be implemented during the MYPD 6 period.

20.2.9 Sales and Load shedding volumes

SALGA wishes clarity on the impact of price elasticity of demand at a sector level. Consideration should be given to impact on sales due to further embedded generation. It was suggested that Eskom should deduct load shedding volumes in the revenue application

The impact of price elasticity and embedded generation was considered when the sales forecasting was undertaken. Eskom plans to meet the projected sales demand. The load shedding volumes, if any, will not be known over a year in advance. Load shedding is undertaken to manage the system.

20.2.10 Return on Assets

Clarity is sought on the level of return on assets being applied for

It is clarified that Eskom is applying for ROA of 4%, 5% and 6% for each of the application years. This is a contribution towards the migration towards cost reflectivity. If Eskom were to implement the ROA equivalent to the WACC, then the revenue being applied for will be significantly higher.

21 Conclusion

The revenue application demonstrates that Eskom will not be in a position to earn a fair return as required by the ERA. Eskom has proposed a significant sacrifice to its liquidity and financial sustainability, to allow for continual subsidy to all electricity consumers.

It has been illustrated that a significant price increase is being requested for FY2026 which drops in the subsequent two years of the application. The initial adjustment is driven mainly by the impact of the introduction of negotiated pricing agreements, correction of NERSA's previous decisions and the need to improve the level of ROA for migration towards sustainability. In the subsequent two years the increase related to Eskom's primary energy costs and operating costs are negative or insignificant. The key drivers are the continuation of improvement in return on assets contribution, IPPs and the impact of the introduction of the carbon tax liability.

Eskom acknowledges that operating efficiency needs to be continuously strived for. This remains a focus for the application years. The benefit of addressing the Municipal debt burden will go a long way in contributing to Eskom's financial sustainability.

From the period FY 2016 to FY 2027, Eskom would have received over R480bn of support in different forms. This includes direct equity, direct support through a temporary loan (switch to equity), loan conversion and debt transfer. This in essence is an indirect subsidy to all electricity consumers. The higher the usage by a customer, the greater the subsidy. In addition, the electricity prices in South Africa must be cost reflective before any sector reform. The migration over the next few years together with urgently addressing the Municipal debt will contribute to the sustainability of Eskom. This will allow Eskom to continue to play a pivotal role in the growth of economy.