NATIONAL ENERGY REGULATOR OF SOUTH AFRICA

In the matter regarding

Eskom's Sixth Multi-Year Price Determination (MYPD6) Application – Generation Business

By

ESKOM HOLDINGS SOC LIMITED ('ESKOM')

The Draft Decision

Based on the available information and the analysis performed, the Energy Regulator decided at its meeting on 30 January 2025 that:

1. The allowable revenues, as per Table 1, must be recovered for Eskom Generation Business using the tariffs approved by the National Energy Regulator of South Africa (NERSA).

Table 1: Total allowable revenue decision for Generation Business

Allowable Revenue (R' millions)	Application FY2026	NERSA adjustment	NERSA decision	Application FY2027	NERSA adjustment	NERSA decision	Application FY2028	NERSA adjustment	NERSA decision
Regulates Assest Base(RAB)	828 717	-61 682	767 035	909 656	- 206 515	703 141	893 438	- 301 421	592 017
WACC%	4,00%		4,00%	5,00%		5,00%	6,00%		6,00%
Returns	33 149	-2 468	30 681	45 483	-10 326	35 157	53 606	-18 085	35 521
Primary Energy	125 030	-4 153	120 877	129 493	-2 315	127 178	124 189	10 101	134 290
International Purchases	-	-	-	-	-	-	-	-	-
IPPs	-	-	-	-	-	-	-	-	-
Environmental levy	6 539	251	6 790	6 279	338	6 617	5 337	881	6 218
Carbon Tax	5 534	-5 534	0	21 291	-21 291	0	19 895	-19 895	0
OPEX	**55 093**	**-8 203**	**46 890**	**55 038**	**-7 644**	**47 394**	**57 427**	**-7 050**	**50 377**
Depreciation	53 054	-21 851	31 203	55 406	-24 140	31 266	61 921	-30 594	31 327
MYPD6 Allowable Revenue	**278 399**	**-41 958**	**236 441**	**312 991**	**-65 378**	**247 613**	**322 376**	**-64 642**	**257 734**
Add: Approved RCA/ Court order for liquidation	13 241		13 241	10 961		10 961			0
Totals MYPD6 Allowable Revenue	**291 640**	**-41 958**	249 682	**323 952**	**-65 378**	258 574	**322 376**	**-64 642**	**257 734**

2. The Energy Regulator may subject the revenues in **Table 1** above to further extensive prudency reviews, efficiency tests and performance thresholds.

TABLE OF CONTENTS

TABLE OF TABLES

TABLE OF FIGURES

ABBREVIATIONS

BER	Bureau for Economic Research
Capex	Capital expenditure
CPI	Consumer Price Index
DAB	Dispute Adjudication Board
DMP	Demand Market Participation
DSLI	Demand Supply Loss Index
DSM	Demand Side Management
Dx	Distribution
EAF	Energy Availability Factor
EEDSM	Energy Efficiency and Demand Side Management
ELS	Electricity Subcommittee
ER	Energy Regulator (NERSA Board)
ERA	Electricity Regulation Act
ERTSA	Eskom's Retail Tariff Structural Adjustments
EUF	Energy Utilisation Factor
ERI	Eskom Rotek Industries
FY	Financial Year
GDP	Gross Domestic Product
GLF	Generation Load Factor
GWh	Gigawatt hour
Gx	Generation
HV	High voltage
IAS	International Accounting Standard
IDM	Integrated Demand Management
IPP	Independent Power Producer
IRP	Integrated Resource Plan
km	Kilometre
kWh	Kilowatt hour
LF	Load factor
MIRTA	Minimum Information Requirement for Tariff Application
MW	Megawatt
MWh	Megawatt hour
MYPD	Multi-Year Price Determination
NERSA	National Energy Regulator of South Africa
NPA	National Prosecuting Authority
OCGT	Open Cycle Gas Turbine
OCLF	Other Capability Loss Factor
Opex	Operating expenditure
PAJA	Promotion of Administrative Justice Act

PCLF	Planned Capability Loss Factor
PPA	Power Purchase Agreement
PPE	Property Plant and Equipment
RAB	Regulatory Asset Base
RCA	Regulatory Clearing Account
REC	Regulator Executive Committee
REIPP	Renewable Energy Independent Power Producer
RfD	Reasons for Decision
SADC	Southern African Development Community
SAPS	South African Police Service
SARS	South African Receiver of Revenue
SIU	Special Investigation Unit
SOC	State-Owned Company
Tx	Transmission
UCLF	Unplanned Capability Loss Factor
UoS	Use-of-System
WUC	Work Under Construction

DEFINITIONS

Energy Availability Factor (EAF) – is the difference between the maximum availability and all unavailability (PCLF, UCLF and OCLF) expressed as a percentage. This excludes renewables, IPPs and international imports.

Planned Capability Loss Factor (PCLF) – is the ratio between the unavailable energy of the units that are out on planned maintenance over a period compared to the total net installed capacity of all units over the same period.

Unplanned Capability Loss Factor (UCLF) – is the ratio between the unavailable energy of the units that are out on unplanned outages over a period compared to the total net installed capacity of all units over the same period.

Other Capability Loss Factor (OCLF) – is the ratio between the unavailable energy of the units that cannot be dispatched, due to constraints out of the power station management control, over a period compared to the total net installed capacity of all units over the same period.

1. LEGAL MANDATE

1.1 Section 4(c) of the National Energy Regulator Act, 2004 (Act No. 40 of 2004) (NERA) empowers the National Energy Regulator of South Africa (NERSA) with the responsibility to undertake the functions detailed in section 4 of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) (‘the ERA’).

1.2 The ERA sets out the powers and functions of NERSA. Of relevance to this application is section 4(a)(ii), wherein NERSA is empowered and required to set and approve prices and tariffs in a manner prescribed by a rule.

1.3 In performing its mandated functions, NERSA is required to ensure that the following objects are achieved:

a) The efficient, effective, sustainable and orderly development and operation of electricity supply infrastructure in South Africa.
b) That the interests and needs of present and future electricity customers and end users are safeguarded and met, having regard to the governance, efficiency, effectiveness and long-term sustainability of the electricity supply industry within the broader context of economic energy regulation in the Republic.
c) That investment in the electricity supply industry is facilitated.
d) That universal access to electricity is facilitated.
e) That the use of diverse energy sources and energy efficiency is promoted.
f) That competitiveness and customer and end-user choice are promoted; and
g) That a fair balance among the interests of customers and end users, licensees, investors in the electricity supply industry and the public is facilitated.

1.4 In order to facilitate compliance with the regulatory framework and create regulatory certainty regarding Eskom’s revenue applications, NERSA developed a Multi-Year Price Determination (MYPD) Methodology in line with section 14(1)(g) of the ERA and Minimum Information Requirements for Tariff Applications (MIRTA) in line with section 14(1)(e) of the ERA, which Eskom must comply with, but does not restrain the exercising of discretion by the Energy Regulator when taking a decision.

1.5 The licences issued to Eskom set out conditions for the setting and approval of tariffs, charges, prices and rates charged by Eskom.

1.6 In terms of section 15 of the ERA, a licence condition relating to the setting and approval of tariffs, charges, and prices, and the regulation of revenue must, inter alia, enable an efficient licensee to recover the full cost of its licensed activities, and a reasonable return proportionate to the risk of the licensed activity; provide for or prescribe incentives for continued improvement of the technical and economic efficiency with which services are to be provided; and give end users proper information regarding the costs that their consumption impose on the licensee's business.

1.7 It is important to take note of the amendments to the ERA that have a material impact on the legal mandate, namely section 15(1A) where tariff determinations must take into account all planned projects reflected in the integrated resource plan and the transmission development plan insofar as these projects shall impact on the costs of the licensee, for the period during which the tariff shall apply and section 15(1B) where the Regulator must in the case of vertically integrated licensees, set or approve separate tariffs for each of the licensed activities listed in section 4(*a*)(i).

1.8 The previous judgement against NERSA has shown that before discretion is exercised on the issues of deviation from the agreed methodology, such discretion should be exercised reasonably with due regard to the country's economy, as well as the interests of the customers and those of Eskom as a licensee. Failure to exercise these principles of discretion may result in prejudice against the already afforded rights within the agreed methodology.

Legal Overview of the Decision-Making of the Application

1.9 The submission of an application by Eskom Generation and its consideration by the Energy Regulator find homage in the Electricity Regulation Act, read with the Electricity Pricing Policy and the Multi-Year Price Determination Methodology. Reference to other authorities is a fundamental found in the disciplines of economics, accounting and engineering and is widely accepted as such.

1.10 As an administrative body, NERSA is duty-bound on receipt of the application to satisfy the constitutional requirement embodied in section 33 of the Constitution of the Republic of South Africa and the National Energy Regulator Act of 2004, read with the Promotion of Administrative Justice Act of 2000 (PAJA). This consultative requirement is distinct from substantive evaluation, but combined, they satisfy the legality requirement.

1.11 Consultation applies to all levels and types of decision-making or policy formulation, whether of a legislative or executive nature and whether at the national, provincial or local government levels. The South African Constitution makes it pertinent that in any form of decision-making or policy formulation, adequate and deliberate consultations, and by extension, public participation must have been conducted for such decision or policy to pass the test of legality and rationality. This contribution seeks to tease out the content and application of this constitutional imperative in practice in relation to the role of administration in decision-making and policy formulation and to highlight the emphasis the courts have placed on the imperative of adopting the right consultative mechanisms in such processes.

1.12 Section 33 of the Constitution has been fleshed out in sections 3 and 4 of the Promotion of Administrative Justice Act, which place further duties on administrators generally and sets out how administrators shall fulfil their constitutional obligations when implementing legislation and policies. The sections give important guidance on the nature of the duty to engage. For example, section 4 speaks to the holding of a public inquiry and a proper consideration of the inputs received. Sections 3 and 4 of PAJA are aimed at ensuring a proportional balance of competing interests, implying that the effect of administrative action must be balanced against the need to take measures aimed at realising socio-economic rights. Generally, the procedural fairness requirements would facilitate rational and accurate decision-making in the provision of socio-economic goods and services, as it provides an opportunity for the voices of individuals and communities to be heard before final decisions are made.

What is it that NERSA has Done to Give Effect to Procedural Fairness

1.13 On initiating a process to consider the revenue application, internal mechanisms to safeguard the adequacy of the application were raised to assess the application on whether the contents thereto are sufficient to enable consideration, compliance with applicable laws and regulatory methodologies, the application was found to be sufficient, hence the decision of the Energy Regulator.

1.14 To satisfy the requirement of section 10 of the National Energy Regulator Act and section 4 of PAJA, NERSA published the application for stakeholder written comments. It was ensured that the publication was meaningful (stakeholders were able to make comments), the period was adequate (stakeholders were given a reasonable period), the application was accessible (stakeholders were directed on where to find the application), information on where the comments should be submitted was provided and that stakeholders were allowed an extension of time where reasons advanced were sustainable.

1.15 Subsequent to the notice and comment process, we proceeded to advertise circular public hearings in all provinces of the Republic, wherein stakeholders were given another opportunity to make oral representations on the application even if they did not submit written comments, observers from all walks of life were allowed to ensure that the process is open, fair and accessible.

1.16 The stakeholder consultation process was not a gimmick just to circumvent the operation of the law but a valuable means that the comments received were analysed, considered and factored into the decision-making process, which resulted in the lawful, reasonable and rational decision that has been made.

The Double Sidedness of the Need to Consult

1.17 The process of considering the Eskom application requires consultation in line with the Constitution and other laws, including regulatory instruments developed to enable efficient and effective administration. This requirement is binding on the need to engage Eskom Generation when considering the application in instances wherein a need to deviate from a documented regulatory approach arises.

1.18 The approach would require an outline of what the existing regulatory approach provides, the proposed new approach and the reasons for the change. A response from Eskom Generation must be received and Eskom Generation cannot unreasonably withhold the response on consent.

1.19 This principle seeks to ascertain the regulatory certainty in approved mechanisms, and this was emphasised by the Court in the *Eskom v NERSA* judgement (case no.37296/2028 at para 72) on the usage of the Methodology to assess and consider Eskom's revenue application. This means we cannot arbitrarily deviate from the Methodology without observing the need for consultation.

1.20 The analysis of the application has been conducted without invoking the need to deviate from the regulatory instruments approved for the purposes of considering the application. The usage of generally accepted practices and principles within economics, accounting and engineering in the consideration of the application does not require evoking the consultation requirement as the regulatory mechanisms have not generated a new means separate from them.

Public Interest Requirement and How It is Applied

1.21 Section 9(f) of the National Energy Regulator Act requires the Energy Regulator to act in public interest, whereas section 10 of the same Act requires the decisions of the Energy Regulator to be also in public interest. This requirement places an obligation jointly and severally on the members of the Energy Regulator when considering this application not only to be consumed by technical considerations but to have a view on public interest.

1.22 By placing the obligation on the persons of the Energy Regulator and the output (decision), the consideration is obligatory. In the *Borbet* judgement (Eskom and NERSA were appellants), the Supreme Court of Appeals referenced that the existence of the need to consider public interest allows NERSA the latitude to exercise ‘reasonable judgment’ after due consideration of what may be in public interest.

1.23 The simple consideration we have taken on what ‘public interest’ is that an action or process benefits the public rather than a single person or entity. It can also refer to the general welfare of the public or the promotion of the public’s well-being.

1.24 Such ability is tested against reasonability, as the court has alluded. When technical, financial and economic analysis has been done, the duty to determine what a reasonable consideration is begins. The navigation to arrive at what is reasonable took into account that efficient and/or prudent costs have been considered, and an undue burden on Eskom has also been avoided.

1.25 The following has been looked into in arriving at the decision:

a. Inflation and export prices
b. Household affordability
c. Economic indicators
d. Gross Domestic Product
e. Investment
f. Economic sectors

g. Other relevant factors.

1.26 In arriving at this decision, the Energy Regulator had to balance both Eskom's interests and those of the public in line with section 2(b) of the ERA by thoroughly analysing the financial information submitted by Eskom, conducting an economic impact assessment study and considering the public's representations.

1.27 The analysis of the financial information tested the prudency of all costs presented by Eskom. At the same time, the economic impact assessment depicted the potential impact of electricity tariff increase on inflation, economic growth, job creation (employment) and income generation, international trade and the responsiveness of demand for electricity.

1.28 Importantly, the economic factors considered in the economic assessment are directly linked to the potential impact that the revenue application may have on the economy and the public at large, while the financial analysis focused on the sustainability of Eskom to continuously provide electricity to the public within the confines of efficiency standards.

1.29 It is also important to note that economic impact assessment findings align with the arguments/issues raised during the nationwide public hearings. Specifically, the public interest issues were centred on affordability (access to electricity due to loss of income) and loss of employment opportunities.

1.30 In making the decision, the Energy Regulator has taken into account the matters raised by the consumers or the public at large and Eskom. The Energy Regular is also mindful of the obligation placed by the objectives of the ERA and government policies.

2. THE APPLICANT

2.1 The Generation Business (hereafter referred to as Generation) is a wholly owned Eskom Holdings SOC Ltd subsidiary. It is central to the Government's strategic objective to establish a more competitive, efficient, and sustainable electricity supply industry.

2.2 The 1998 White Paper on Energy Policy proposed an introduction of competition in the energy sector, beginning with the restructuring of Eskom by splitting it into three independent entities for electricity generation, transmission and distribution. This proposal was later articulated and refined in the 2019 Department of Public Enterprises (DPE) Eskom Roadmap, which outlined the future of Eskom, starting with the creation of Transmission, which is fully regulated and wholly owned by Eskom and will act as a network, system and market operator to set the electricity industry on a new path. Section 5.3 of the MYPD4 Methodology states that each division's revenue will be calculated separately, with the overall price/revenue determined at Generation level and communicated as such to customers.

3. BACKGROUND AND INTRODUCTION

3.1 Eskom submitted its MYPD6 Generation revenue application on 16 August 2024. In this application, Eskom is making a total revenue application of R291 640m, R323 952m and R322 376m for FY2025/26, FY2026/27 and FY2027/28, respectively. This includes Regulatory Clearing Accounts (RCAs) and court decisions.

Table 2: Generation application

Allowable Revenue (R' millions)	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Regulates Assest Base(RAB)	828 717	909 656	893 438	870 825	861 267
WACC%	4,00%	5,00%	6,00%	7,47%	9,69%
Returns	33 149	45 483	53 606	65 085	83 491
Primary Energy	125 030	129 493	124 190	125 267	128 681
International Purchases					
IPPs					
Environmental levy	6 539	6 279	5 337	4 781	4 767
Carbon Tax	5 534	21 291	19 895	19 274	20 948
Arrear debt					
Employee Benefits E +	14 281	14 858	15 176	15 774	16 519
Maintenance	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	53 054	55 406	61 921	62 927	67 812
MYPD6 Allowable Revenue	**278 399**	**312 991**	**322 376**	**335 269**	**366 696**
Add: Approved RCA/ Court order for liquidation	13 241	10 961			
Total MYPD6 Allowable Revenue	**291 640**	**323 952**	**322 376**	**335 269**	**366 696**

3.2 The areas on which the application will be analysed are as follows:

a) Primary energy
b) Environmental levy
c) Carbon tax
d) Employee benefits
e) Maintenance
f) Other operating costs
g) Depreciation

4. THE DECISION-MAKING PROCESS

4.1 On 23 September 2024, NERSA published Eskom's MYPD6 Generation application on the NERSA website and an invitation for stakeholders to submit written comments. The closing date for comments was 1 November 2024 to allow for the 30-day consultation period requirement.

4.2 Four stakeholders applied for and were granted extension as follows:

a) Business (BUSA) – 30 November 2024
b) City Power – 30 November 2024
c) Energy Intensive Users (EIUG) – 30 November 2024
d) Sasol – 30 November 2024.

4.3 NERSA conducted public hearings in all eight provinces of South Africa from 18 November to 7 December 2024 to solicit comments from interested and affected stakeholders. The Free State and Northern Cape provinces were combined due to proximity and low number of registered stakeholders who wished to present.

4.4 The Energy Regulator made its determination on the application on 30 January 2025.

5. STAKEHOLDER COMMENTS

5.1 More than 1 278 written stakeholder comments (these comments were not all specific to Generation but were cutting across the three businesses) were received from private individuals, small energy users, intensive energy users, non-government organisations (NGOs) and environmental activists, as well as from local government and other stakeholders as follows:

5.1.1 AfriForum
5.1.2 Agri Limpopo
5.1.3 Agri SA
5.1.4 Agri Western Cape
5.1.5 Grain SA
5.1.6 SA Cane Growers Association
5.1.7 Vinpro
5.1.8 AgriCulture Mpumalanga
5.1.9 BOSA
5.1.10 City of Cape Town
5.1.11 Communicase NPC
5.1.12 eThekwini Ratepayers and Residents Associations
5.1.13 eThekwini Ratepayers Protest Movement
5.1.14 eThekwini United Ratepayers Business and Civics Organisation
5.1.15 Msunduzi Association of Residents
5.1.16 Ratepayers and Civics
5.1.17 Department of Premier – Western Cape
5.1.18 Street Committees – 4092
5.1.19 G4CA
5.1.20 Groundwork
5.1.21 Individual
5.1.22 National Association of Social Housing Organisation
5.1.23 OUTA

5.1.24 Project 90 by 2030
5.1.25 General Industries Workers Union of SA
5.1.26 SAFCEI
5.1.27 SAIPPA
5.1.28 New Church
5.1.29 SALGA
5.1.30 Ubuntu Culture and Heritage foundation
5.1.31 United Front Greater Johannesburg Region
5.1.32 Waterberg Environmental Forum

5.2 Thirty-two stakeholders, as listed above, submitted technical comments.

5.3 Inputs from stakeholders have been analysed, and they form part of the RfD.

6. ANALYSIS OF ESKOM'S MYPD6 APPLICATION

6.1 Regulatory Asset Base (RAB)

Summary of the application

6.1.1 Eskom applied for a return on assets calculated on all assets shown in Table 3 below (Table 21 in Eskom's application summary). This application assumes closing RAB values of R1 183 895m, R1 201 861m and R1 236 628m for the MYPD6 period. These values are largely driven by the existing fixed assets (DRC values), as shown in Table 3 below.

Table 3: RAB summary of the Eskom application

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**

6.1.2 In line with Eskom's application, the regulatory asset base is comprised of the following:

6.1.2.1 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).

6.1.2.2 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.

6.1.2.3 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 before the assets are placed in Commercial Operation (CO) are included in the RAB and earn a rate of return.

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

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

6.1.3 NERSA relies on section 9 of the MYPD4 Methodology, which deals with the calculation of depreciation, networking capital and work under construction, to reach an RAB decision. The applicable sections of the Methodology are quoted in the various components that make up the total RAB.

NERSA ANALYSIS

Depreciated Replacement Costs (DRC) – Fixed Assets in Use

6.1.4 Eskom applied for a Gx DRC of R611 670m for FY2025/26 (FY2026/27: R572 153m, FY2027/28: R533 036m), as shown in Table 4 below. Eskom indicated that the roll forward of the depreciated replacement costs for MYPD6, as shown below, is based on MYPD5 approved values.

Table 4: Eskom DRC application

TABLE 55: GENERATION - FIXED ASSETS - DRC VALUES (R'M)

Generation - Fixed assets - DRC Values (R'm)	FY2024	FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Opening balance	234 534	696 821	653 176	611 670	572 153	533 036	494 789
Inflation on opening balance	-	-	-	-	-	-	-
Land & Buildings							
Revaluation reserves	507 817	-	-	-	-	-	-
Transfers from Work Under Construction (WUC)	-	-	-	-	-	-	-
Depreciation	(45 530)	(43 646)	(41 505)	(39 517)	(39 117)	(38 248)	(37 203)
Closing asset values	**696 821**	**653 176**	**611 670**	**572 153**	**533 036**	**494 789**	**457 585**

6.1.5 Furthermore, the R507bn added back in 2024 is because of the decision from the Court, which ruled that the Energy Regulator was not supposed to deduct this amount in the 2023 decision.

6.1.6 The following extracts from the MYPD Methodology sections are pertinent in deriving the DRC:

6.1.6.1 9.2.2 The Energy Regulator has adopted an asset valuation methodology whereby the current cost of replacing an asset with its modern equivalent asset is adjusted for physical deterioration and all relevant forms of obsolescence and optimisation to allow reasonable return on such RAB to ensure the financial viability and sustainability of Eskom while preventing unreasonable price volatility and excessive returns.

6.1.6.2 9.2.4 Depreciated Replacement Cost (DRC) will be used as the basis for estimating the cost of constructing a modern equivalent asset.

6.1.6.3 9.2.5 DRC will be derived from the modern equivalent asset value for the replacement of fixed assets that have been adjusted by accumulated depreciation taking into account the age and condition of the asset.

6.1.6.4 9.2.6 The MEAV focuses on valuing the cost of assets needed to provide the equivalent service provided by existing assets.

6.1.7 In calculating the DRC, the following steps were followed by both NERSA and Eskom:

6.1.7.1 Step 1: Determination of the replacement cost new (RCN) values

6.1.7.2 Step 2: Adjusting the RCN with accumulated depreciation

6.1.7.3 Step 3: Adjusting for technical obsolescence.

Step 1: Determination of the replacement cost new (RCN) values

6.1.8 In order to calculate the RCN, NERSA and Eskom used overnight costs. This concept is derived from a hypothetical scenario in which a power station is constructed over one night. It forms a relevant baseline to assess cost, with current prices, should the plant have been built that way. This concept is, therefore, a simple method for comparing costs for different power stations. To achieve this, the cost-to-capacity formula is used.

6.1.9 The cost-to-capacity formula is used in the valuation of power plants (and other types of industrial facilities) to estimate the cost of building or expanding plants of different sizes. The formula is based on the principle that costs do not increase linearly with capacity; instead, there are economies of scale, meaning larger plants are often less expensive per unit of capacity than smaller ones. The cost-to-capacity formula is expressed in line with the figure below.

$$cost_1 = cost_0 \times \left[\frac{cap_1}{cap_0}\right]^x$$

where:

$cost_1$ is the cost of the subject plant

$cost_0$ Is the cost of the benchmark plant

cap_1 Is the capacity of the subject plant

cap_0 Is the capacity of the benchmark plant

x is an exponent factor related to the expected cost-to-capacity benefit

6.1.10 Table 5 below shows a comparison of the overnight cost assumptions used by Eskom and the three comparative institutions relied on by NERSA.

Table 5: Overnight cost assumption comparison

Fuel Type	Eskom 2020 (ZAR/kW)	Eskom 2020 ($/kW)	Capacity Benchmark (MW)	NREL 2020 ($/kW)	NREL 2020 (ZAR/kW)	IEA 2020 ($/kW)	IEA 2020 (ZAR/kW)	BNEF 2020 ($/kW)	BNEF 2020 (ZAR/kW)
Coal	40,177	2,678	4,500	1,500 - 3,000	22,500 - 45,000	1,400 - 3,200	21,000 - 48,000	1,800 - 3,400	27,000 - 51,000
Coal RTS	40,177	2,678	4,500	1,500 - 3,000	22,500 - 45,000	1,400 - 3,200	21,000 - 48,000	1,800 - 3,400	27,000 - 51,000
Nuclear	92,957	6,197	1,940	5,000 - 9,000	75,000 - 135,000	4,800 - 8,500	72,000 - 127,500	6,000 - 10,000	90,000 - 150,000
Gas	11,534	769	132	700 - 1,300	10,500 - 19,500	600 - 1,200	9,000 - 18,000	800 - 1,400	12,000 - 21,000
Hydro (pumped storage)	30,406	2,027	1,332	1,500 - 3,500	22,500 - 52,500	1,200 - 3,200	18,000 - 48,000	1,800 - 3,800	27,000 - 57,000
Hydro (conventional)	26,371	1,758	1,332	1,000 - 2,500	15,000 - 37,500	900 - 2,400	13,500 - 36,000	1,200 - 2,800	18,000 - 42,000
Hydro (other)	26,648	1,777	1,332	1,000 - 2,500	15,000 - 37,500	900 - 2,400	13,500 - 36,000	1,200 - 2,800	18,000 - 42,000
Wind	30,298	2,02	100	1,100 - 2,300	16,500 - 34,500	1,000 - 2,200	15,000 - 33,000	1,200 - 2,500	18,000 - 37,500
Coal FGD (New Build)	50,051	3,337	4,500	2,000 - 4,000	30,000 - 60,000	2,100 - 4,500	31,500 - 67,500	2,500 - 4,800	37,500 - 72,000

6.1.11 National Renewable Energy Laboratory (NREL), International Energy Agency (IEA) and Bloom New Energy Finance's (BNEF) values are depicted as a range to account for regional variations, technology differences and other factors influencing costs.

6.1.12 The cost assumptions are adjusted to R/kW using an approximate exchange rate of R15:1 USD for 2020. This is the same exchange rate used by Eskom.

6.1.13 The use of these comparisons provides a benchmark for evaluating whether Eskom's assumed costs are in line with international standards or whether there is a need for NERSA to make adjustments.

6.1.14 Eskom relied on EPRI for its estimates used in the 2020 RAB valuation. These estimates fall within a reasonable range for all three institutions used for comparison, as demonstrated in Table 6 below. As a result, NERSA deemed the assumptions reasonable and relied on them to compute the RCN. In applying the cost-to-capacity formula, the RCN outcomes are depicted in Table 6 below.

6.1.15 In calculating the RCN, NERSA used the cost-to-capacity formula and assumed the full capacity of the plant. This is a conservative approach that allows maximum benefit from economies of scale. NERSA then removes the RCN of all inoperable units before adjusting for accumulated depreciation. This is done in line with Eskom's units expected to be online during the application period, as depicted in Table 6 below. The table shows the names of power stations, the corresponding unit numbers and the expected time for them to come online.

Table 6: Eskom operable units

.	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
Komati										N/A
Arnot	01-Apr-29	31-Aug-29	31-Jul-29	31-Mar-30	24-Nov-29	31-May-29	N/A	N/A	N/A	N/A
Camden	30-Aug-29	30-Apr-29	30-Nov-29	31-Jan-29	30-Dec-29	31-Jul-29	31-Mar-30	31-Aug-29	N/A	N/A
Grootvlei	16-Aug-29	31-Mar-30	04-Sep-29				N/A	N/A	N/A	N/A
Hendrina		10-Feb-29		31-Mar-29	31-Dec-29	13-Sep-29	19-Apr-29			21-May-29
Kriel	05-May-29	13-Jun-29	27-Jan-30	21-Feb-30	12-Mar-30	31-Mar-30	N/A	N/A	N/A	N/A
Duvha	17-Aug-31	30-Sep-31		30-Jun-33	30-Mar-33	21-Feb-34	N/A	N/A	N/A	N/A
Matla	22-Aug-30	29-Jun-31	11-Dec-31	15-Oct-32	23-Aug-33	20-Jul-34	N/A	N/A	N/A	N/A
Kendal	30-Sep-39	19-Jun-41	15-Dec-42	30-Nov-42	23-Dec-43	09-Dec-44	N/A	N/A	N/A	N/A
Kusile	29-Aug-68	30-Oct-70	30-Aug-71	30-Jun-72	31-Dec-72	30-Jun-73	N/A	N/A	N/A	N/A
Lethabo	21-Dec-36	10-Jul-37	26-Mar-37	02-Dec-38	30-Jun-40	27-Dec-41	N/A	N/A	N/A	N/A
Majuba	31-Mar-46	31-Mar-47	31-Mar-48	31-Mar-49	31-Mar-50	31-Mar-51	N/A	N/A	N/A	N/A
Matimba	03-Dec-38	03-Dec-38	28-Sep-39	29-Sep-40	30-Sep-41	30-Sep-42	N/A	N/A	N/A	N/A
Medupi	31-Jul-71	30-May-69	30-Oct-68	30-Nov-67	30-Apr-67	31-Aug-65	N/A	N/A	N/A	N/A
Tutuka	30-Dec-35	30-Dec-36	30-Dec-37	30-Dec-37	30-Dec-39	30-Dec-41	N/A	N/A	N/A	N/A

Source: The Generation Strategic Review for the Continued Operations of the Power Plants

6.1.16 All other qualifying RAB elements are dealt with separately.

Step 2: Adjusting the RCN with accumulated depreciation

6.1.17 In order to compute the accumulated depreciation, NERSA compared the original commissioning dates of the individual plants with the revised estimates of the decommission dates/remaining useful lives as depicted in

Eskom’s latest asset valuation exercise as of March 2020. The figure below is an extract from the valuation report.

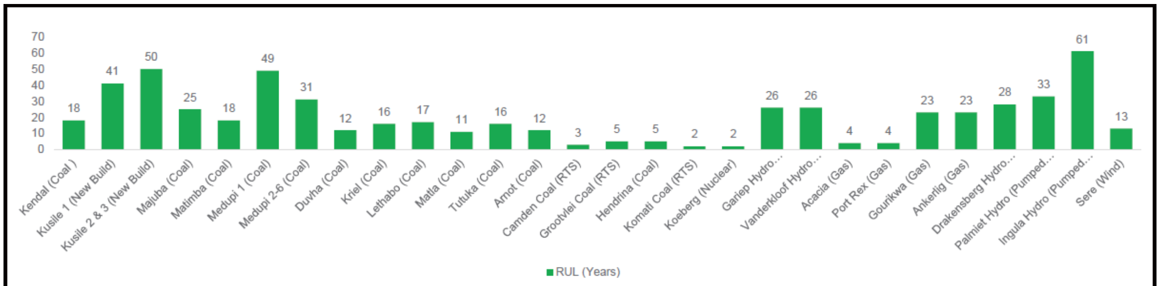

Figure 4.7: RULs of Eskom's Power Stations

Figure 1: Eskom remaining useful lives (RUL) as at March 2020

6.1.18 This allowed NERSA to have a forecast of the deemed total plant life in years, as depicted in the table below.

Table 7: Deemed total plant life

Power Station	Station Type	Original Commissioning Date (Year)	Eskom Decommissioning Date (Year)	NERSA Deemed total useful life (years)	Eskom Remaining Useful Life (Years) as at 2020	NERSA Effective Depreciated years
		A	B	C = B - A	D	E = C - D
Kendal	Coal	Oct-88	Oct-43	55	23	32
Kusile	Coal FGD	Jul-17	Jul-70	53	50	3
Majuba	Coal	Apr-96	Apr-50	54	30	24
Matimba	Coal	Dec-87	Dec-41	54	21	33
Medupi	Coal	Dec-15	Dec-69	54	49	5
Duvha	Coal	Aug-80	Aug-33	53	13	40
Kriel	Coal	May-76	May-39	63	19	44
Lethabo	Coal	Dec-85	Dec-40	55	20	35
Matla	Coal	Sept-79	Sept-33	54	13	41
Tutuka	Coal	Jun-85	Jun-39	54	19	35
Arnot	Coal	Sept-71	Sept-35	64	15	49
Camden (RTS)	Coal (RTS)	Apr-67	25-Apr	58	5	53
Grootvlei (RTS)	Coal (RTS)	Jun-69	25-Jun	56	5	51
Hendrina	Coal	May-70	26-May	56	6	50
Komati (RTS)	Coal (RTS)	Nov-61	22-Nov	61	2	59
Koeberg	Nuclear	Jul-84	24-Jul	40	4	36
Gariep	Hydro	Sept-71	Sept-57	86	37	49
Vanderkloof	Hydro	Jan-77	Jan-58	81	38	43
Acacia	Gas	May-76	30-May	54	10	44
Port Rex	Gas	Sept-76	28-Sept	52	8	44
Gourikwa	Gas	Jul-07	Jul-43	36	23	13
Ankerlig	Gas	Mar-07	Mar-43	36	23	13
Drakensberg	Hydro (Pumped)	Jun-81	Jun-53	72	33	39
Palmiet	Hydro (Pumped)	Apr-88	Apr-59	71	39	32
Ingula	Hydro (Pumped)	Jan-16	Jan-87	71	67	4

6.1.19 NERSA subtracted the remaining years from the deemed total plant life to get the effective years that the plant should be depreciated, thereby allowing the calculation of the accumulated depreciation as of March 2020 as follows:

A = Original commissioning date
B = Decommissioning date (Eskom estimates as at March 2020)
C = Deemed total useful life: (C = B – A)
D = Remaining useful life (Eskom estimates as at March 2020)
E = Effective depreciated years: (E = C – D)
M = Annual depreciation: (M = RCN / C)
N = Accumulated depreciation: (N = M x E)

Step 3: Adjusting for technical obsolescence

6.1.20 Eskom calculated technical obsolescence adjustments based on the excess maintenance costs and excess capitalisation costs and ensured that elements external to the assets were eliminated and not considered in the calculation.

6.1.21 The concept of excess maintenance costs is based on technical obsolescence, a form of depreciation in which the loss in value or usefulness of a property is caused by inefficiencies or inadequacies, as well as excess capitalisation costs.

6.1.22 NERSA is satisfied that the approach taken by Eskom to adjust for technical obsolescence is reasonable; therefore, no further adjustments were deemed necessary. NERSA has allowed the same adjustment to the extent that it does not result in a negative value. Furthermore, NERSA implicitly considers excess capitalisation, overruns and any other inefficiencies when determining the RCN. This is because the RCN is based on a benchmark plant with reasonable overnight costs.

Residual Values

6.1.23 Where subject assets are still being used in current operations and their remaining useful lives are zero, Eskom used a minimum ‘residual value’ rather than a zero or negative value. Moreover, where the asset was stated to be non-operational, it has been considered at the end of life and thus at its residual value.

6.1.24 NERSA excluded plants that have reached the end of life and those that are non-operational, both from earning a return and depreciation, respectively.

6.1.25 In order to calculate the DRC as at March 2020, the RCN is adjusted for accumulated depreciation and technical obsolescence, as demonstrated in the Table 8 below.

Table 8: Technical obsolescence

Generation DRC as at 30 March 2020	Installed Units	Operating Units	RCN			Accumulated Physical Depreciation			Technical Obsolescence			DRC as at March 2020			DRC as at March 2026		
			Eskom	Adjustment	NERSA	Eskom	Adjustment	NERSA	Eskom	Adjustment	NERSA	Eskom	Adjustment	NERSA	Eskom	Adjustment	NERSA
Kendal	6	6	165 368	(12 756)	152 612	(92 739)	3 946	(88 793)	(642)	0	(642)	71 987	(8 809)	63 178			49 304
Kusile	6	6	58 268	109 036	167 304	(6 880)	(2 590)	(9 470)	(397)	0	(397)	50 991	106 446	157 437			141 653
Majuba	6	6	165 127	(12 937)	152 190	(71 223)	3 583	(67 640)	(436)	0	(436)	93 468	(9 354)	84 114			70 022
Matimba	6	6	160 306	(7 694)	152 612	(91 454)	(1 809)	(93 263)	(85)	0	(85)	68 767	(9 503)	59 264			45 133
Medupi	6	6	163 948	3 356	167 304	(18 882)	3 391	(15 491)	(608)	0	(608)	144 458	6 747	151 205			135 713
Duvha	6	5	144 637	(46 036)	98 601	(92 843)	18 427	(74 416)	(5 220)	0	(5 220)	46 574	(27 609)	18 965			9 663
Kriel	6	6	120 530	(36 851)	83 679	(65 718)	7 276	(58 442)	(609)	0	(609)	54 203	(29 575)	24 628			17 986
Lethabo	6	6	148 976	(27 106)	121 870	(88 345)	10 791	(77 554)	(543)	0	(543)	60 088	(16 314)	43 774			32 694
Matla	6	6	144 637	(26 316)	118 321	(96 902)	7 066	(89 836)	(253)	0	(253)	47 482	(19 250)	28 232			17 276
Tutuka	6	6	146 806	(25 090)	121 716	(90 765)	11 875	(78 890)	(746)	0	(746)	55 295	(13 215)	42 080			30 810
Arnot	6	6	94 496	(41 795)	52 701	(64 211)	23 862	(40 349)	(820)	0	(820)	29 465	(17 933)	11 532			7 414
Camden (RTS)	8	8	62 716	(38 531)	24 185	(44 753)	22 653	(22 100)	(134)	0	(134)	17 829	(15 878)	1 951			0
Grootvlei (RTS)	6	3	47 409	(40 303)	7 106	(29 356)	22 884	(6 472)	(6 373)	0	(6 373)	11 680	(11 680)	0			0
Hendrina	10	6	76 055	(55 122)	20 933	(60 417)	41 727	(18 690)	(4 559)	0	(4 559)	11 079	(11 079)	0			0
Komati (RTS)	9	0	39 775	(39 775)	-	(31 965)	31 965	0	(5 738)	0	(5 738)	2 072	(2 072)	0			0
Koeberg	2	2	180 336	1	180 337	(161 125)	(1 178)	(162 303)	(20)	0	(20)	19 191	(1 177)	18 014			0
Gariep	4	4	9 494	(8 003)	1 491	(4 934)	4 084	(850)	0	0	0	4 560	(3 918)	642			555
Vanderkloof	2	2	6 329	(5 633)	696	(4 018)	3 649	(369)	0	0	0	2 311	(1 985)	326			283
Acacia	3	3	1 972	0	1 972	(1 707)	100	(1 607)	0	0	0	265	100	365			183
Port Rex	3	3	1 972	0	1 972	(1 622)	(47)	(1 669)	0	0	0	350	(47)	303			114
Gourikwa	5	5	8 605	0	8 605	(2 612)	(495)	(3 107)	0	0	0	5 993	(495)	5 498			4 303
Ankerlig	9	9	15 433	0	15 433	(4 844)	(729)	(5 573)	0	0	0	10 589	(729)	9 860			7 717
Drakensberg	4	4	30 354	(6 188)	24 166	(17 221)	4 131	(13 090)	(106)	0	(106)	13 027	(2 057)	10 970			9 292
Palmiet	2	2	14 319	(10 003)	4 316	(6 931)	4 986	(1 945)	0	0	0	7 388	(5 017)	2 371			2 067
Ingula	4	4	38 398	(22 010)	16 388	(2 496)	2 496		(428)	0	(428)	35 474	(19 514)	15 960			15 960
Sere	46	46	3 030	(231)	2 799	(1 089)	1 089		(276)	0	(276)	1 665	858	2 523			2 523
Nicora	3	2	65	(65)	0	(34)	34		0	0	0	31	(31)	0			0
Second Falls	2	2	-	0	-		0		0	0	0	-	0	0			0
First Falls	2	2	-	0	-		0		0	0	0	-	0	0			0
Colley Wobbies	3	1	1 108	(1 058)	50	(1 074)	1 074		0	0	0	34	16	50			50
Total	193	173	2 050 469	(351 112)	1 699 357	(1 156 160)	224 242	(931 918)	(27 993)	0	(27 993)	866 316	(113 078)	753 238	611 670	(18 121)	593 549

6.1.26 However, because the Eskom application year is from FY2025/26, the DRC balance has been rolled forward by adjusting the accumulated depreciation from 2020.

6.1.27 It is NERSA's decision to allow Generation a RAB of R593 549m, R561 612m and R529 674m for the application years, respectively, in line with the Table 9 below.

Table 9: Generation DRC

Generation RAB Summary(R'millions)	2025/26			2026/27			2027/28		
	Eskom	Adjustments	NERSA	Eskom	Adjustments	NERSA	Eskom	Adjustments	NERSA
Depreciated Replacement Costs (DRC)	611 670	(18 121)	593 549	572 153	(10 542)	561 612	533 036	(3 363)	529 674

Assets Transferred to Commercial Operation

6.1.28 Eskom applied for assets transferred from work under construction (WUC) to commercial operations of R224 221m for the 2025/26 financial year (FY2026/27: R256 027m, FY27/28: R281 300m).

6.1.29 Eskom indicated that these transfers refer to generation assets transferred into commercial operation subsequent to the 2020 asset valuation. Once commissioned, these assets are depreciated by dividing the cost of the asset over the number of years for which the asset will be used, i.e. the useful life of the asset.

6.1.30 In assessing transfers to commercial operations, NERSA relied mainly on the following sections of the MYPD Methodology:

6.1.30.1 9.1.8 Only assets used in regulated business operations that meet the following criteria will be included in the RAB to allow the licensee to earn a reasonable return on assets based on the WACC:

6.1.30.2 9.1.8.1 Fixed assets must be used and useable, which means that assets should be in a condition that makes it possible to supply demand in the short-term (within 12 months).

6.1.30.3 9.1.8.2 Fixed and other assets that are not used and/or in a useable form will therefore not be included in the RAB.

6.1.30.4 9.1.8.3 The exception to the criteria is that the capital expenditure of expansionary nature, to create additional capacity (i.e. which is not used and usable) should be capitalized and included in the RAB as an when construction costs are incurred for return purposes.

6.1.31 These transfers emanating from WUC should originate from capital expenditure for the creation of additional capacity in order to qualify. This is in line with section 9.1.8.3 of the MYPD Methodology.

6.1.32 These transfers that Eskom applied for relate to cumulative capital expenditure previously approved by NERSA, which relates to various projects intended for either replacement, refurbishment or upgrade to parts of a particular plant. These activities have a net zero impact on the overall value of the plant since they are not increasing capacity.

6.1.33 This is because, in valuing Eskom assets, the value of a modern plant is assumed. As a result, the expectation is that Eskom plants would have all the technology that a modern plant would and comply with legislation. Therefore, Eskom’s expenditure on these activities should not affect the value of the plant, except for the expenditure on new build.

6.1.34 As a result, NERSA only allowed transfers relating to the new build (Medupi and Kusile), as these qualify as capacity additions in line with the Methodology.

6.1.35 It should be noted that Eskom did not submit a RAB revaluation study in line with the applicable MYPD Methodology for this current application. This submission would have allowed NERSA to assess an Eskom RAB that already includes these transfers to individual plants, not the application in its current form, which values transfers separate from the DRC of any given plant.

6.1.36 The RAB is approved on condition that Eskom submits the revaluation with the next RCA application.

Work Under Construction

6.1.37 Eskom applied for a WUC of R41 750m for the 2025/26 financial year (FY2026/27: R49 359m, FY2027/28: R54 378m), which comprises previously incurred and future capital expenditure for the application period.

6.1.38 In assessing the WUC, NERSA relied mainly on the following section of the MYPD Methodology:

6.1.38.1 ***9.6 Work Under Construction***

6.1.38.2 9.6.1 Capital WUC are qualifying construction costs incurred with respect to projects with a long construction period (longer than 12 months).

6.1.38.3 9.6.2 Capital WUC should be stated at cost consisting of the cost of material and direct labour and any cost directly attributable to bringing it to its present location and condition.

6.1.38.4 9.6.3 To the extent that the assets are financed by borrowing, such borrowing costs attributable to construction of qualifying assets will not be capitalised as part of these assets over the period of construction.

6.1.38.5 9.6.4 The criteria for allowing inclusion of WUC as part of the RAB are as follows:

6.1.38.6 9.6.4.1 The WUC projects to be included in RAB are with respect to the creation of additional generation, transmission and distribution capacity.

6.1.38.7 9.6.4.2 The WUC projects for additional electricity generation undertaken must be evaluated against the Integrated Resource Plan (IRP) of the National Government of South Africa. The Energy Regulator must be able to evaluate and compare such a project with similar projects that Eskom has undertaken in the past.

6.1.38.8 *9.6.4.3 The WUC must not necessarily be based on the least-cost model of the IRP; however, the least cost model should be seen as an indication of the costs.*

6.1.38.9 *9.6.4.4 Costs in the WUC programme must be disaggregated with full details on the activities undertaken.*

6.1.38.10 *9.6.4.5 All WUC allowed must be subject to reviews and audits and any amounts identified to be imprudent must not be allowed in the risk management device on an annual basis*.

6.1.39 Eskom indicated that Generation-related capital expenditure plans will focus on delivering the following projects:

6.1.39.1 New build programme – commercial operation of the remaining unit of Kusile

6.1.39.2 Technical plan capital expenditure

6.1.39.3 Investment in cost-plus mines which will provide Generation with a more sustainable source of coal. This is included as future fuel.

6.1.39.4 Investment in projects to reduce particulate emissions and water consumption, on the journey towards environmental compliance.

6.1.40 Table 10 below provides a breakdown of Eskom Generation's capital expenditure requirements.

Table 10: Capex summary

TABLE 59: GENERATION CAPEX SUMMARY

Total Generation Capex (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
New build and major projects	7 581	10 865	11 700	11 200	12 800	11 700	19 019	13 449
Outage capex	8 422	9 900	14 601	15 290	15 347	21 251	9 212	10 519
Tech Plan capex	3 642	3 613	11 226	17 026	23 524	18 938	4 626	5 448
Nuclear future fuel	1 179	1 064	1 392	1 412	1 463	1 693	3 283	1 696
Coal & Water future fuel	1 704	2 447	3 990	3 631	1 814	2 113	1 060	2 291
Renewables	-	-	551	4 090	2 787	777	1 376	42 587
Asset Purchases	556	559	560	593	629	667	0	0
Total Gx Licence Capex	**23 084**	**28 447**	**44 020**	**53 242**	**58 363**	**57 138**	**38 576**	**75 989**

6.1.41 In assessing Eskom's capital expenditure requirements, only Capex relating to capacity expansion will be allowed and capitalised. This goes back to the point made in section 6.1.33 above. As a result, only capital expenditure for capacity expansion over and above the units already accounted for in Table 6 above, which details the units expected to be operable in the application years and have been included as part of RAB.

6.1.42 As a result, only Capex relating to new build and major projects has been allowed.

Stakeholder Comments on WUC

6.1.43 Some stakeholders indicated that WUC should be excluded from RAB for purposes of earning a return.

NERSA Analysis of Stakeholder Comments on WUC

6.1.44 In terms of the MYPD4 Methodology, WUC must be included in the RAB.

Net Working Capital

6.1.45 Eskom Generation applied for net working capital of R42 007 million for 2025/26FY, R19 423 million for 2026/27FY and R18 003 million for 2027/28FY. This includes trade and other receivables, inventory and future fuel less trade and other payables.

6.1.46 In assessing the net working capital, NERSA relied mainly on the following section of the MYPD Methodology:

6.1.47 ***9.5 Net Working Capital***

6.1.48 9.5.1 Net working capital refers to trade receivables, reasonably incurred future fuels less trade payables required for the operation of the regulated business.

6.1.49 9.5.2 Trade receivables represent current assets due to the utility because of the sale of electricity on credit. A maximum of 45 days sale of electricity by the regulated business operations will be included in the RAB to the extent that such trade receivables do not attract interest in the hands of the utility.

6.1.50 9.5.3 Inventory refers to coal, nuclear fuel, maintenance spares and consumables held in efficiently operation of the regulated business.

6.1.51 9.5.4 Trade payables refer to current liabilities for which the amount to be settled is usually with respect to the normal operations of the utility and excludes provisions. A minimum trade payable turnover of 60 days of trade purchases from *suppliers will be included in the RAB to the extent that such payables do not attract interest payments.*

Table 11: Generation net working capital

Generation	Application 2025/26	Adjustment	NERSA	Application 2026/27	Adjustment	NERSA	Application 2027/28	Adjustment	NERSA
Inventory	61 849	-11 933	49 916	63 819	-11 527	52 292	67 646	-11 500	56 146
Plus: Closing accounts receivable(Debtors) (45 days)	481	0	481	480	0	480	473	0	473
Plus: Future Fuel (amortised value)	10 498	0	10 498	9 864	0	9 864	9 933	0	9 933
Less: Closing accounts payable (Creditors) (60 days)	-30 821	0	-30 821	-54 740	0	-54 740	- 60 050	0	-60 050
Closing Net Working Capital	**42 007**	**-11 933**	**30 074**	**19 423**	**-11 527**	**7 895**	**18 003**	**-11 500**	**6 502**

6.1.52 Eskom included coal stockpiles exceeding 42 days as part of the inventory. The coal stockpile days are at an average of 82 days over the MYPD6 period, which is above the 42 days allowed as per stock day policy. This is due to Medupi having a stockpile that will last for over 300 days, which is caused by Eskom delays in completing construction and commissioning the power plant. During MYPD5, Eskom mentioned measures in place to bring and maintain stock days at expected levels. But still, there is no change. The average number of stock days was 79 in MYPD5 and, currently, the average is 84 days over the MYPD6 period.

6.1.53 Even though Eskom might be keeping extra stock as a contingency to mitigate potential future coal supply, stockpiling more coal may lead to coal being degraded over time, environmental concerns, and storage and handling costs.

The amount for these stockpiles has been disallowed, and only coal stockpiles of 42 days or less are allowed by NERSA.

6.1.54 Measures to bring and maintain stock days at expected levels are as follows:

6.1.54.1 Modify coal supply agreements to minimise coal volumes.

6.1.54.2 Reallocate excess stock to stations that have the capacity to receive, use or stock it.

6.1.54.3 Eskom must also consider alternative strategies to manage high stockpiles, e.g. improving supply chain efficiency and coal quality management.

6.1.55 In line with section 9.5.2 of the MYPD4 Methodology, the debtors are allowed as applied for, as they are all within a period of 45 days.

6.1.56 In line with section 9.5.4 of the MYPD4 Methodology, the creditors are allowed as applied for, as they are all within a period of 60 days.

6.1.57 In line with section 9.5.3 of the MYPD4 Methodology, the future fuel costs are allowed as applied for. This is to encourage Eskom to invest in cost-plus mines that will provide Generation with a more sustainable source of coal. The risk of disallowing future fuel costs is that cost-plus mines will be unable to produce the forecasted volumes, resulting in Eskom procuring from relatively expensive short-term contracts, which NERSA is trying to discourage.

Stakeholder Comments on Net Working Capital

6.1.58 Some stakeholders have expressed that including net working capital in the RAB is not beneficial, as items like debtors and short-term liabilities, such as borrowings, do not provide long-term benefits beyond fulfilling previous commitments or settling outstanding amounts.

NERSA Analysis of Stakeholder Comments on Net Working Capital

6.1.59 The MYPD Methodology allows the inclusion of net working capital as part of the RAB to enable different operations (Generation, Transmission and Distribution) to meet short-term obligations.

Asset Purchases

6.1.60 Eskom applied for Asset Purchases of R1 221 million for the 2025/26 financial year (FY2026/27: R1 480m, FY2027/28: R1 717m).

6.1.61 Asset Purchases represent all movable items that are purchased and are ready to be used in relation to operations, including the acquisition and replacement of equipment, vehicles, machinery, tools and furniture.

NERSA Analysis of Asset Purchases

6.1.62 Section 9.1.8.1 of the MYPD Methodology makes provision for the inclusion of assets that are used and usable to make it possible to supply demand in the short term (12 months).

6.1.63 The trend analysis was conducted by observing the approved Regulatory Clearing Accounts (RCAs) from MYPD4 and MYPD5 and determining the quantum of the approved values in relation to the Asset Purchases for the Generation Business. These were averaged over a three-year period, and they totalled R1 346 million. This has been considered to be consistent with the MYPD6 application.

6.1.64 It is NERSA's decision to approve the Generation Business asset purchases as applied for.

6.1.65 Figure 1 below illustrates the historical trend of actual expenditure in line with approved RCAs in MYPD4 and MYPD5 relative to the MYPD6 application, which shows that the asset purchases are in line with historical trends.

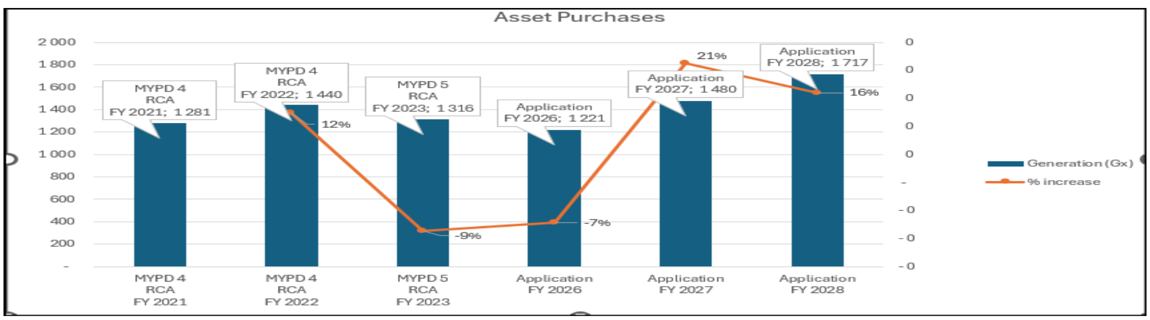

Figure 2: Historical trend analysis – asset purchases for Generation

6.1.66 These asset purchases have been recommended as applied for.

Assets Funded Upfront by Customers

6.1.67 Eskom applied for zero assets funded upfront by customers for the MYPD6 period, and this has been recommended as applied for.

Table 12: Generation total RAB summary

Generation RAB Summary(R'millions)	2025/26			2026/27			2027/28		
	Eskom	Adjustments	NERSA	Eskom	Adjustments	NERSA	Eskom	Adjustments	NERSA
Depreciated Replacement Costs (DRC)	611 670	(18 121)	593 549	572 153	(10 542)	561 611	533 036	(3 363)	529 674
Assets transferred to commercial operation post valuation date	224 221	(78 020)	146 201	256 027	(252 249)	3 778	281 300	(277 065)	4 235
Work Under Construction (WUC)	41 750	(15 290)	26 460	49 359	(15 347)	34 012	54 378	(21 251)	33 127
Working capital	42 007	(11 933)	30 074	19 423	(11 527)	7 896	18 003	(11 500)	6 503
Asset purchases	1 221	0	1 221	1 480	0	1 480	1 717	0	1 717
Assets funded by customers upfront	0	0	0	0	0	0	0	0	0
Total RAB	**920 869**	**(123 364)**	**797 505**	**898 442**	**(289 665)**	**608 777**	**888 434**	**(313 179)**	**575 256**
Average RAB	**828 717**	**(61 682)**	**767 035**	**909 656**	**(206 515)**	**703 141**	**893 438**	**(301 421)**	**592 017**

6.1.68 Table 12 above shows that Eskom is applying for a total RAB of R920 869m for FY2025/26 (FY2026/27: R898 442m, FY2027/28: R888 434m). NERSA decided to allow R797 505m, R608 777m and

R575 256m for the application years, respectively, in line with the analysis in the sections above.

Depreciation

6.1.69 Eskom applied for Depreciation of R53 054m for the 2025/26 financial year (FY2026/27: R55 406m, FY2027/28: R61 921m), as shown in Table 13 below.

Table 13: Generation depreciation

TABLE 56: GENERATION DEPRECIATION

GENERATION - DEPRECIATION (R'm)	Decision FY2024	Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Depreciated Replacement Costs (DRC)	45 530	43 646	41 505	39 517	39 117	38 248	37 203
Asset transferred to commercial operation post valuation date	10 817	15 724	11 243	15 520	22 374	24 335	30 334
Assets Purchases	32	43	305	370	429	343	275
Assets funded upfront by customers	123	124	-	-	-	-	-
Total Depreciation	**56 502**	**59 537**	**53 054**	**55 406**	**61 921**	**62 927**	**67 812**

6.1.70 In assessing the depreciation, NERSA relied mainly on the following section of the MYPD Methodology:

6.1.70.1 9.4 Depreciation on Regulatory Asset Base

6.1.70.2 Calculation of Depreciation

6.1.70.3 9.4.1 Annual Depreciation will be calculated by deducting the Accumulated Depreciation of the previous year (year-1) from the Accumulated Depreciation the current year (year 0) using the following formula:

6.1.70.4 $D = ACy0 - ACy{-1}$

6.1.70.5 D *= Depreciation and amortisation of replacement cost adjustment*

6.1.70.6 $ACy0$ *= MEAV*(remaining economic life year 0/total economic life)*

6.1.70.7 $ACy{-1}$ *= MEAV*(remaining economic life year -1/total economic life)*

6.1.70.8 9.4.2 The economic life for the regulated Generation, Transmission and Distribution assets shall be determined by the Energy Regulator in consultation with the relevant stakeholders.

6.1.70.9 9.4.3 The RAB to be used for the depreciation of the assets will be the RAB as approved by the Energy Regulator. The DRC is arrived at, for each regulated asset, by the following steps:

6.1.70.10 9.4.3.1 Step one: Eskom will submit the MEAV study to the Energy Regulator.

6.1.70.11 9.4.3.2 Step two: The Energy Regulator will review and approve an appropriate MEAV value.

6.1.70.12 9.4.3.3 Step three: This MEAV value is then depreciated (according to the expired economic life and remaining economic life of the asset) to arrive at the DRC. Formula DRC = MEAV(remaining economic life/total economic life).*

6.1.70.13 9.4.3.4 Step four: Phase in the DRC on a straight-line basis over the MYPD4 period. The Energy Regulator may adjust the period in the light of Eskom's progress in implementing its investment programme.

6.1.70.14 9.4.4 WUC will be excluded from RAB for the purposes of depreciation.

Table 14: Generation depreciation

Generation Depreciation (R'm)	2025/26			2026/27			2027/28		
	Eskom	Adjustments	NERSA	Eskom	Adjustments	NERSA	Eskom	Adjustments	NERSA
Depreciated Replacement Costs (DRC)	41 505	(10 608)	30 897	39 517	(8 620)	30 897	39 117	(8 220)	30 897
Assets transferred to Commercial Operations	11 243	(2 667)	8 576	15 520	(12 603)	2 917	22 374	(19 353)	3 021
Asset purchases	305	0	305	370	0	370	429	0	429
Assets funded by customers upfront	0	0	0	0	0	0	0	0	0
Total	**53 053**	**(13 275)**	**39 778**	**55 407**	**(21 223)**	**34 184**	**61 920**	**(27 573)**	**34 347**

6.1.71 This depreciation has been adjusted in line with the DRC and transfers to commercial operations in the sections above. As a result, NERSA has approved a depreciation of R39 778m for the 2025/26 financial year (FY2026/27: R34 184m, FY2027/28: R34 347m).

Weighted Average Cost of Capital (WACC)

Summary of Eskom's Application

6.1.72 The determination for the WACC is made, but it is not implemented to the full extent in this MYPD 6 revenue application. Eskom has applied for a lower WACC of 4% in FY2025/26, 5% in FY2026/27 and 6% in FY2027/28. The proposed WACC is for the smoothing of the tariff to allow the average price of electricity to migrate towards cost-reflective tariffs. In the absence of such a phasing, the requested price increase will be significantly higher.

Weighted Average Cost of Capital Formula

6.1.73 The Weighted Average Cost of Capital (WACC) is the weighted average of the expected cost of equity and cost of debt. The following formula will be used to determine the pre-tax real WACC:

$$WACC=[\{Kd\times g\}+\{Ke/(1-tc)\times(1-g)\}]$$

Where:

$WACC$ = pre-tax, real cost of capital

Kd = pre-tax cost of debt

g = gearing

Ke = post-tax cost of equity

tc = company tax rate

6.1.74 The table below shows the calculation of Eskom's WACC for the MYPD 6 tariff application.

Table 15: Eskom WACC calculation

WACC Calculation - Eskom MYPD 6	
Capital Structure	
Debt-to-Total Capitalization	60,00%
Equity-to-Total Capitalization	40,00%
Cost of Debt	
Risk free rate	10,059%
Debt premium	3,500%
Cost of Debt before tax	**13,559%**
Cost of Equity	
Risk-free Rate	10,059%
Market Risk Premium	6,000%
Levered Beta	0,82
Cost of Equity after tax	**14,98%**
Tax rate	27,00%
Cost of Equity before tax	**20,52%**
Nominal WACC before tax	**16,34%**
Inflation	5,00%
Real WACC before tax	**10,80%**

6.1.75 The explanation of the parameters based on the formula used by Eskom in calculating its WACC is detailed below.

Cost of Debt

6.1.76 Section 8.2.1 of the Tariff Methodology details that the formula for the expected real cost of debt consists of the expected risk-free rate and the utility's debt premium. Section 8.2.2 states that the cost of debt is determined by using the following formula:

$$\boxed{Kd = rf + d\text{Þ}}$$

Where:

rf = Risk-free rate
dÞ = The debt premium

i) Risk-free rate (Rf)

Eskom used the Rf based on the South African 10-year bond rate. The rate is a 40-day average rate taken at a point in time. The risk-free rate has increased over the past few years. This is due to the slow global economic recovery post COVID, including the Russia-Ukraine war.

ii) Debt premium (Dp)

Eskom's credit rating has been downgraded on numerous occasions to various levels below investment grade, coupled with this, the balance sheet is heavily leveraged. As a result, the debt premium has remained relatively the same since MYPD5. The debt premium is also aligned with Eskom seeking out debt on an unguaranteed basis.

Cost of Equity

6.1.77 Section 8.4.1 of the Methodology indicates that the Cost of Equity (Ke) must be determined by the Capital Asset Pricing Model (CAPM, applying the following formula:

$$\boxed{Ke = [rf + (\beta \times MRP)]}$$

Where:

rf = Risk-free rate

B = beta
MRP = Market Risk Premium

iii) Beta (β)

Since a company's equity beta is strongly related to that company's debt level, Eskom looked at the betas of listed utilities around the world in relation to their debt levels and normalised it for Eskom's debt to equity ratio. The betas for these utilities are at different levels because these utilities have different debt levels. Eskom's beta is calculated at 0.82.

iv) Market risk premium (Rm-Rf)

The market risk premium that is calculated and published in Credit Suisse's Global Investment Returns Yearbook 2023 was used.

v) Capital structure

The capital structure consists of a weighting of equity and debt with Eskom at 60% for debt and 40% for equity. The change in the capital structure is due to the significant government support Eskom has received over the past few years.

vi) Inflation

The forecasted inflation rate is based on a combination of IMF World Economics, Bloomberg Economics, the National Treasury, the Reserve Bank forecasts and the Eskom Treasury. Accordingly, 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 5% for the year.

vii) Tax rate

The company tax rate of 27%, as prescribed by the South African Revenue Service (SARS), was used.

6.1.78 This has resulted in a nominal WACC of 16.3% remaining relatively stable and the real WACC of 10.80% decreasing from MYPD5 (11.5%) due to a higher inflation estimate.

NERSA Analysis

6.1.79 NERSA has determined a WACC for Eskom, as detailed in Table 16, to ensure compliance with the MYPD Methodology.

Table 16: NERSA WACC calculations

NERSA - WACC Calculation	
Capital Structure	
Debt-to-Total Capitalization	60,00%
Equity-to-Total Capitalization	40,00%
Cost of Debt	
Risk free rate	10,040%
Debt premium	2,240%
Cost of Debt before tax	**12,280%**
Cost of Equity	
Risk-free Rate	10,040%
Market Risk Premium	6,000%
Levered Beta	0,82
Cost of Equity after tax	**14,96%**
Tax rate	27,00%
Cost of Equity before tax	**20,49%**
Nominal WACC before tax	**15,57%**
Inflation	4,40%
Real WACC before tax	**10,69%**

6.1.80 The WACC calculated by NERSA amounts to 10.69%, which differs from the WACC calculated by Eskom. The reason for the difference is detailed below:

i) The difference between Eskom's calculated WACC is the debt premium because Eskom maintained an MYPD5 debt premium of 3.5%. NERSA calculated the debt premium of 2.24%, which is made up of current Eskom long-term debt less the risk-free. The other difference is that Eskom used an inflation rate of 5%, and NERSA used an average inflation rate of 4.4% per BER.

Approach/Methodology Used

Weighted average cost of capital formula

6.1.81 The following formula is used to determine the WACC:

$$WACC=[\{Kd \times g\}+\{Ke/(1-tc) \times (1-g)\}]$$

a) Risk-free rate (Rf)

The risk-free rate is calculated as an average of the market-to-market rate of nominal government bond with at least 10-year maturity. The calculation will consider the preceding 30 days, starting at least two months before the submission of the tariff application.

b) Debt premium (Dp)

In contrast to what is indicated by Eskom in its application, on 24 November 2023, S&P Global Ratings (S&P Global) announced its decision to upgrade Eskom's long-term issuer credit rating to 'B' from 'CCC+'.

In the rationale, the credit rating agency stated that the upgrade was due to its expectation that the South African government's R254 billion financial support package, as part of the Eskom Debt Relief Act signed into law on 7 July 2023, would cover Eskom's debt servicing and repayment obligations over the current and coming two financial years, resulting in an improvement of the company's credit quality.

This contradicts Eskom's statement that indicates the downgrade of its credit rating to levels below investment grade, resulting in a debt premium that has remained relatively the same since MYPD5.

For this reason, the debt premium used by NERSA is calculated by determining the difference between the Eskom bonds and the risk-free rate (12.28% - 10.04% = 2.24%).

c) Beta (β)

β = The beta must be determined by proxy. As a proxy, the average of at least six utility companies listed in the stock exchange will be used. The approach taken to benchmark Eskom's beta for each business unit is to look at the betas of other listed utilities around the world.

d) Market risk premium (Rm-Rf)

NERSA used the MRP of 6% as published by Credit Suisse.

e) Capital structure

The capital structure consists of a weighting of equity and debt. NERSA strives to use an optimal targeted gearing ratio for Eskom. Eskom's actual leverage as detailed in the annual financial statement (AFS) for the FY2022/23 is 61/39, hence NERSA maintained Eskom's proposed capital structure of 60/40.

f) Inflation

The forecasted inflation rate is sourced from Bureau for Economic Research (BER) and averaged over the MYPD6 tariff application. The BER inflation rate is 4.4%, which is an average of 4.5%, 4.4% and 4.4% for the 2025, 2026 and 2027 full years.

g) Tax rate

The company tax rate of 27%, as prescribed by the South African Revenue Service, is used.

NERSA Adjustments and Reasons

6.1.82 NERSA's calculation for the real pre-tax WACC resulted in 10.69%. All assumptions are detailed in Table 16 above.

6.1.83 This is backed by the market data marked by the 10-year SA Government Bond reaching a 10.04% mark (sourced on 8 November 2024).

6.1.84 Even though the calculated WACC is 10.69%, Eskom applied for a WACC of 4%, which resulted in a return of (R828 717 x 4%) R33 149m for FY2025/26. Eskom reiterated during the public hearings that the lower WACC amount is meant to address affordability. NERSA applied a WACC of 4% on the adjusted RAB, which resulted in a return of (R767 035m x 4%) R30 681m for the Gx business.

6.1.85 For FY2026/27, Eskom applied a 5% WACC, which resulted in a return of (R909 656 x 5%) R45 483m. NERSA used the same WACC on the adjusted RAB, resulting in (R703 141m x 5%) R35 157m for the Gx business.

6.1.86 For FY2027/28, Eskom applied a 6% WACC, which resulted in a return of (R893 438 x 6%) R53 606m. NERSA used the same WACC on the adjusted RAB, resulting in (R592 017 x 6%) R35 521m for the Gx business.

6.1.87 The use of the applied for WACC instead of the calculated WACC is to achieve the requirements of section 2.2.1 of the MYPD Methodology, which states that the Energy Regulator should ensure Eskom's sustainability as a business and limit the risk of excess or inadequate returns.

6.1.88 NERSA has considered Eskom's liquidity and debt servicing requirements by allowing a return based on a WACC of 4%, 5% and 6% as applied for by Eskom for the respective financial years. This is within the context of balancing the interest of the applicant, the provider of the regulated service and the consumer.

6.1.89 The phasing-in of the ROA will allow consumers to experience a smoother price increase while balancing Eskom's sustainability and the consumers' affordability and allow the economy to adjust towards the migration of cost reflectivity.

Return on Assets

6.1.90 The return on asset included in the MYPD6 application is shown in Table 17 below. Generation is applying for a 4%, 5% and 6% ROA for FY2025/26, FY2026/27 and FY2027/28, respectively.

Table 17: Generation return on assets

Gx Return on Assets	Decision FY2024	Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Closing RAB (R'm)	796 763	736 565	920 870	898 442	888 434	853 216	869 319
Average RAB (R'm)	555 007	766 664	828 717	909 656	893 438	870 825	861 267
RoA Applied for RoA %	1.70%	1.58%	4.00%	5.00%	6.00%	7.47%	9.69%
RoA Applied for (R'm)	9 435	12 113	33 149	45 483	53 606	65 085	83 491

6.1.91 The return on assets is being phased to allow for the smoothing of the tariff and the impact of high increases on consumers and the economy. This phasing allows the average price of electricity to migrate towards cost-reflective tariffs. In the absence of such a phasing, the requested price increase will be significantly higher. Thus, NERSA is allowing a migration to enable consumers to experience a phased price increase. However, this migration is accompanied by risks that should be managed. Should the risks materialise, a further burden is likely to be applied to the fiscus. The efficient costs do not go away and need to be funded.

Approach/Methodology Used

6.1.92 All calculations in the above section align with the Methodology as outlined in sections 9.3 and 9.3.3, which state that the Energy Regulator will use reasonable regulatory judgment to balance the need to smooth price increases, ensure the licensee receives a reasonably cost-reflective return on investment, and prevent excessive or inadequate returns.

Conditions for Approval

6.1.93 The Energy Regulator has not imposed conditions for Eskom since the calculated WACC is in line with the Methodology. Furthermore, Eskom applied for a lower and reasonable WACC when calculating the Return on Assets.

Stakeholder Comments

Stakeholder Comments	NERSA Analysis
OUTA stated that the WACC that Eskom has applied for is a significant contributor to the electricity price increase applied for in Eskom's MYPD6 revenue application, which is a step change in the return of assets on Eskom's depreciated asset replacement cost, from 1.5% (i.e. R15.6bn) allowed in FY2024/25 to 4% (i.e. R42.7bn) for FY2025/26 in Eskom's MYPD6 application. It is OUTA's view that such step changes in the return on assets should be smoothed and phased in gradually to avoid price shocks to electricity customers and the economy.	NERSA notes the statement from OUTA, and the views were considered in the analysis of the ROA.
In FY2022/23, the debt service totalled approximately R72bn, repayments equalled R39bn and interest expenses were R33bn. Using these figures as a proxy (assuming that debt service in the current financial periods is met and that no further debt drawdowns are made for the FY2025/26 application,	NERSA's analysis on Eskom's proposed ROA ensures that its debt and interest expenses are met in the MYPD6 application.

this would equate to an RoA of 3.09% to allow coverage of interest expenses as a minimum. A possible approach could be to grant the utility a return on assets that allows it to service its interest obligations at a minimum and only be allowed a return of WACC once it achieves sustainability.	

6.2 Operating Expenditure

6.2.1 Operating costs include all the costs involved in the day-to-day running of the business. Eskom Generation's operating costs comprise three categories, namely manpower costs, maintenance and other operating costs. Other income and a pro-rata portion of corporate overheads are also included.

6.2.2 In this application, Eskom is applying for a total of R55 888m for FY2025/26, R55 862m for FY2026/27 and R58 263m for FY2027/28, as summarised in the table below.

Table 18: Overall summary of operating costs

Total Generation Operating Costs (Rm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Manpower	11 792	13 317	13 497	14 281	14 858	15 176	15 774	16 519
Maintenance	16 581	19 322	22 021	21 742	20 693	22 224	21 249	23 462
Other Opex	11 939	12 618	3 942	14 558	14 741	15 085	15 797	15 711
Corporate Overheads	1 994	4 479	5 264	5 527	5 799	5 946	6 159	6 389
Other Income	(2 875)	(243)	(227)	(220)	(230)	(168)	(168)	(168)
Total Generation Operating Costs	**39 431**	**49 503**	**44 497**	**55 888**	**55 862**	**58 263**	**58 810**	**61 913**

6.2.3 Each of the operating expense components listed in the above table is analysed below.

Employee Benefit Costs

Summary of the application

Table 19: Generation employee costs

Employee Benefit Costs (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Gx Total	11 792	13 317	13 497	14 281	14 858	15 176	15 774	16 519

6.2.4 Eskom is applying for employee costs of R14 281m, R14 858m and R15 176m for FY2025/26, FY2026/27 and FY2027/28, respectively.

Table 20: Generation employee headcount

Employee Numbers	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Gx Total	13 237	13 731	13 997	13 691	13 747	13 111	13 111	13 111

6.2.5 The headcount applied for is 13 691, 13 747 and 13 111 for the 2025/26 to 2027/28 financial years.

6.2.6 Eskom indicated that in the current business operations, the Generation's key goal in the short term is to turnaround performance and increase energy availability factor (EAF) in a financially, operationally and environmentally sustainable manner, which requires critical interventions.

6.2.7 Filling of vacancies: The current number of vacancies and performance in Generation require immediate, critical interventions to improve current performance, which will, in turn, enable the future business direction.

- Create leadership stability by filling all vacant positions.
- Fastrack the filling of all vacant positions in the auxiliary plant, including all other critical vacancies.

6.2.8 Skills and competencies: Optimisation of current skill base and new skills is required in the short term.

- Generation will close the skill gaps identified through the conducted skills audit.
- Analyse and assess employees' skills and competency in the auxiliary plant, that is Maintenance, Engineering, Operating and Contracts Management in alignment with the Generation Recovery Plan.
- Review of Generation's learner pipeline to ensure sufficient through-flow of skills to support Operating, Maintenance and Engineering.
- Continue with Generation Technical Leadership Programme and Management Development Programme for Senior Managers, Managers and Supervisors.
- Rolling out Executive Coaching and Mentorship geared for Power Station General Managers.

6.2.9 Change management: Current performance impact on morale needs to be managed as an imperative.

- Establish the Organisational Effectiveness Function in Generation.
- Implement the Change Management and Communication Plan across the whole fleet in support of the Recovery Plan.
- Drive the High-Performance Culture.

Stakeholder Comments

6.2.10 Most stakeholders, including SAICA, FAPA, BUSA and OUTA, stated their concern about the high increases proposed by Eskom in other operating costs, which include a portion of corporate overhead costs. Another concern raised was the fact that Eskom's proposed increases for MYPD6 were within inflationary expectations. However, this was premised on FY2024/25 projections that are considerably higher than the FY2024/25 NERSA decision. When the FY2025/26 period is measured against the FY2024/25 decision, much higher increases are evidenced.

6.2.11 Furthermore, stakeholders raised concerns regarding the decline in Eskom's workforce that is accompanied by increases in employee benefits costs that is above inflation. They further stated that it is difficult to justify salary increases in a scenario where the company is incurring financial losses and then passing these costs onto customers, particularly Megaflex consumers, who are already facing significant affordability challenges.

6.2.12 Nelson Mandela Bay Business Chamber at the public hearing on 27 November 2024, stated that Eskom's personnel costs keep on rising while the output shrinks.

NERSA Analysis on Stakeholder Comment

6.2.13 NERSA agrees with the comments by the stakeholder, NERSA will consider the rising employee costs and together with the corresponding number of employees. NERSA will not allow any unjustified costs of employees in its decision.

6.2.14 NERSA agrees with the stakeholder comments and is in line with the analysis conducted by NERSA shown in **Error! Reference source not found.** and **Error! Reference source not found.**.

NERSA Analysis

Table 21: Trending and application analysis

Emplyee costs	Actual	Actual	Actual	Actual	Actual	Projection	Projection	Application	Application	Application	Forecast	Forecast
Years	2018/19	2019/20	2020/21	2021/22	2022/23	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Generation R'm	9 873	10 283	10 705	10 595	11 792	13 317	13 497	14 281	14 858	15 176	15 774	16 519
Generation Head count	12 743	12 010	11574	12792	13 237	13 731	13 997	13 691	13 747	13 111	13 111	13 111
Precentage increase cost		4%	4%	-1%	11%	13%	1%	6%	4%	2%	4%	5%
Percentage increase head count		-6%	-4%	11%	3%	4%	2%	-2%	0%	-5%	0%	0%
NERSA's FY 2024/2025 decision							10 899					
Percentage increase NERSA decision							31%					

6.2.15 Eskom has used FY2024/25 projections as a base to determine the required revenue in FY2025/26, FY2026/27 and FY2027/28, respectively. The implication of this is that NERSA's 2024/25 decision is ignored in the determination of required revenues. This approach does not align with section 10.4.2, which states that 'Manpower costs should be allowed in accordance with the allowable revenue; any additional expenses over and above what was allowed will be at Eskom's expense, excluding inflationary charges. To address this, NERSA will use its decision adjusted by inflation in determining the required revenues.

6.2.16 As can be seen in the table above, Generation employee costs have not been consistent since the 2018/19 financial year. The increase in FY2022/23 and FY2023/24 has been double digits, 11% and 13%, respectively. Eskom is applying for an average increase of 4%, while the costs over the past six years were at an average of 6%. The headcount has only increased by an average of 1% and has declined to 2% in FY2025/26, 0% in FY2026/27 and -5% in FY2027/28.

6.2.17 When the application amount for the first year is compared with the decision, the percentage increase is 31%, which is higher than the 6% increase based on the projections. This demonstrates that when the NERSA decision is used as a base the increase is significant. Therefore, Eskom needs to align its performance with NERSA's decision.

6.2.18 The table below shows the breakdown of employee costs in terms of basic salary, allowances and incentive bonuses. As seen in the table, the basic salary line item is the highest driver of employee costs, an average of 82%, followed by pension contributions at an average of 7%, leave payouts at 3% and lastly overtime-related costs at 7%. Other cost line items are contributing less than 2%. Generation is projecting to spend an amount of R71m in FY2025/26, R75m in FY2026/27 and R80m in FY2027/28, respectively, on performance bonuses. These costs can be allowed to ensure that employees are motivated to maintain and improve their current performance.

Table 22: Payroll statistics summary – salaries, wages, allowances

Employee Benefit Expense	FY 2026	FY 2027	FY 2028	2026 % Contribution	2027 % Contribution	2028 % Contribution
Salaries	12 046	12 371	12 295	84,35%	83,26%	81,02%
Overtime	1 158	932	1 157	8,11%	6,27%	7,63%
Post-employment medical benefits	127	131	137	0,89%	0,88%	0,90%
Leave	435	458	458	3,05%	3,08%	3,02%
Performance bonus	71	75	80	0,50%	0,51%	0,53%
Pension benefits	1 101	1 132	1 122	7,71%	7,62%	7,39%
Direct costs of employment	**14 938**	**15 098**	**15 249**			
Direct training and development	97	98	102	0,68%	0,66%	0,68%
Temporary and contract staff costs	258	203	167	1,80%	1,37%	1,10%
Other staff costs	206	212	211	1,44%	1,43%	1,39%
Gross employee benefit expense	**15 498**	**15 612**	**15 729**			
Assessments	- 145	- 171	- 169			
Assessments	68	- 8	- 8			
Capitalised to property, plant and equipment	- 1 140	- 575	- 376			
Net Employee Benefit Expense	**14 281**	**14 858**	**15 176**			

6.2.19 **Error! Reference source not found.** Figure 3 below shows the contribution of each generation employee to the nominal installed capacity in MWh. As can be observed, Eskom achieved 4.4MW per employee in 2020/21, which is the highest point in the period considered. Eskom is planning to utilise its employees a little less than the highest point. For the MYPD6 control period, Eskom is applying for 3.7MWh per employee. Therefore, when benchmarking Eskom against itself, Eskom intends to utilise employees less based on installed capacity compared to 2020/21.

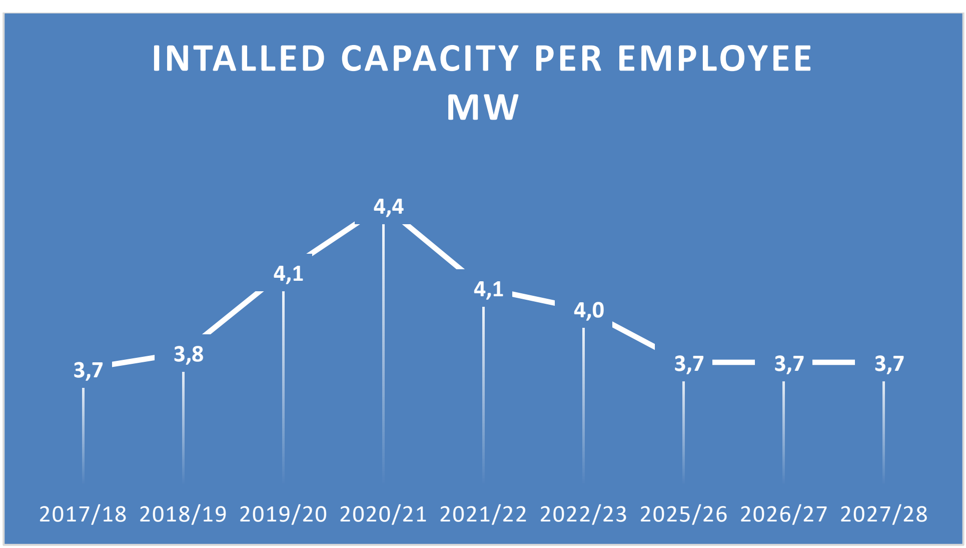

Figure 3: Installed capacity per employee

6.2.20 Figure 4 below shows employees' contribution in the production of energy. Over five years, Eskom's GWh produced per employee was at an overage of 18.12GWh for the 2017/18 to 2022/23 financial years. Eskom's performance was at the highest point in the 2020/21 and 2021/22 financial years, where each employee contributed 19.26GWh and 18.96GWh, respectively.

6.2.21 According to its application, Eskom plans to produce an average of 16.03GWh per employee for the MYPD6 control period, using 13,000 employees, which is less than the 2020/21 and 2021/22 financial years.

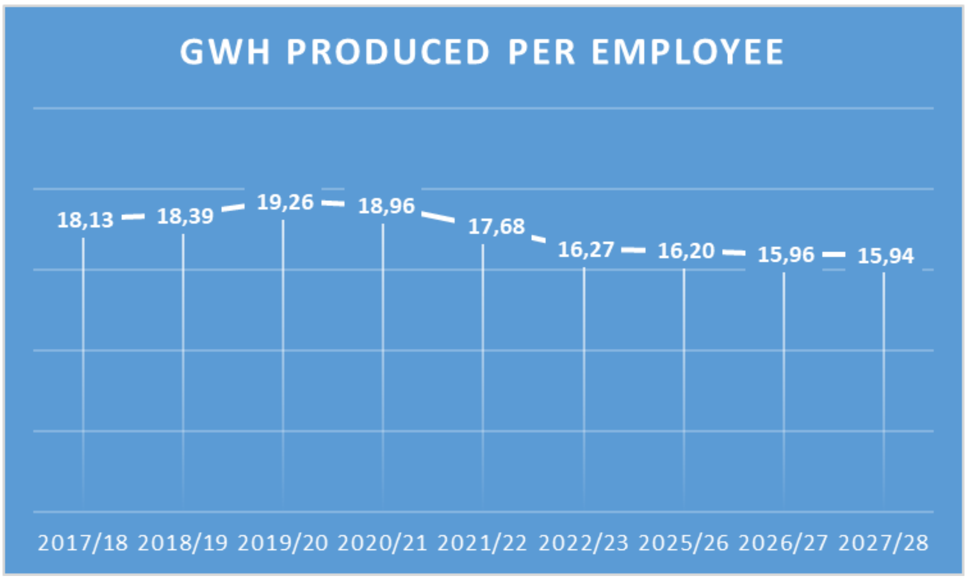

Figure 4: GWh produce per employee

Approach/Methodology Used

6.2.22 Section 10.4.2 of the MYPD4 Methodology states that *manpower costs should be allowed in accordance with the allowable revenue; any additional expenses over and above what was allowed will be at Eskom's expense, excluding inflationary charges*.

6.2.23 Eskom indicated that approximately 78% of the Generation licensee staff complement belongs to the bargaining unit, 21% are positioned at the managerial and 1% at the executive level. As a result, the split for Generation employees, based on the application, will be as per the table below.

Table 23: Employee cost split

Employee Costs Split (R'm)	**Application**	**Application**	**Application**
Years	**FY2026**	**FY2027**	**FY2028**
Generation Barganing employee split at 78%	R 11 139	R 11 589	R 11 837
Generation Managarial split at 22%	R 3 141,82	R 3 268,76	R 3 338,72
Total Application Generation	**R 14 281**	**R 14 858**	**R 15 176**

NERSA Adjustments and Reasons

6.2.24 NERSA has considered inflationary adjustments plus betterment for employees under the bargaining level and only inflationary adjustments for employees under the management level.

6.2.25 Inflation adjustment has been used in line with the Methodology. NERSA approved an amount of R10 899m in FY2024/25, which was split into bargaining employees (R8 502m) and managerial level (R 2 398m). To ensure that Eskom operates at an efficient level, NERSA used its decision made in FY2024/25 of R10 899m as an efficient point.

6.2.26 This amount was adjusted with inflation of 4,5% and a betterment increase of 2,5%. NERSA's decision will be R11 602m for FY2025/26, and for FY2026/27, the amount will be R12 350m after a betterment of 2,6% and inflation of 4.4%. NERSA's decision for FY2027/28 will be R12 903m after considering inflation of 4,4% and a betterment increase of 0.1%.

6.2.27 The above adjustments are further supported by a report published in September 2024 by 21st Century titled – The South African Increase Trend

Report. The report emphasises the importance of balancing market competitiveness, affordability, and internal equity in salary adjustments. While economic conditions show signs of improvement, cautious optimism prevails as organisations navigate structural and external challenges.

6.2.28 The report further emphasises aligning with a 6% salary increase benchmark to ensure competitiveness while maintaining affordability and sustainability. However, NERSA has allowed a 7% salary increase, which is above the recommended benchmark to align with sections 10.4.2 and 10.4.6 of the MYPD4 Methodology. The difference is due to the wage settlement agreements between unions and Eskom.

Table 24: NERSA decision

NESRA decision	**Based decision**	**Application**	**Application**	**Application**
Years	**FY2025**	**FY2026**	**FY2027**	**FY2028**
Generation Barganing employee split at 78%	R 8 502	R 11 139	R 11 589	R 11 837
Inflation rate and betterment Adjustments		1,07	1,07	1,05
Inflationary and betterment Barganing adjustment		R 9 097	R 9 733	R 10 171
Generation Managarial split at 22%	R 2 398	R 3 141,82	R 3 268,76	R 3 338,72
Inflation Adjustments		1,045	1,044	1,044
Inflationary increase-Management		R 2 506	R 2 616	R 2 731
Total Application Generation		R 14 281	R 14 858	R 15 176
Total Adjustments		-R 2 679	-R 2 508	-R 2 273
NERSA decision		**R 11 602**	**R 12 350**	**R 12 903**

6.2.29 To ensure that Eskom operates at an efficient level, NERSA maintains its decision of R 10 899m (made of R8 502 and R2 398m) as an efficient point. This position is then adjusted for inflationary adjustment, including betterment, as per the Methodology.

Maintenance

Summary of the application

6.2.30 Eskom Generation is applying for the maintenance cost for MYPD6 of R21 742m, R20 693m and R22 224m for the 2025/26, 2026/27 and 2027/28 financial years, respectively. Table 25 below shows the MYPD6 application figures for comparison. Eskom has embarked on an extensive Generation Recovery Plan. Eskom states that the Government support package has enabled it to order long lead time parts for the outages and that there has been a dramatic improvement in staff morale. These are contributing factors to the success of the recovery plan. The success of the recovery plan is manifested in improved plant performance, which, in turn, brought about an end to load-shedding.

Table 25: Eskom application

Maintenance Opex (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Gx Total Maintenance Opex	16 581	19 332	22 021	21 742	20 693	22 224	21 249	23 462

NERSA Analysis

6.2.31 Eskom provided a detailed breakdown of the proposed maintenance work. If Eskom can accomplish that work, it can result in much improved plant performance and reduced UCLF, which NERSA requires. In the current application period, affordability is a key issue that must be addressed. In this regard, consideration must be given to the alternative to spending on maintenance, which is unreliable plant that results in load-shedding. In practical terms, load shedding has been particularly hard on low-income households where perishable food has been spoiled and wasted due to delays in restorations. The public testified at the hearings in the past that their local shops sell spoiled perishable food because load-shedding has broken the cold chain. Therefore, on this basis, the affordability question must be answered, and yes, it is better than the alternative.

6.2.32 In studying the maintenance plans, the Kusile breakdown maintenance is excessive compared to other stations. It is also not clear whether the provisions are based on experience or actual maintenance that is planned. Therefore, it is set at the average of the other stations with breakdown provisions, with the balance disallowed.

Approach/Methodology Used

6.2.33 Section 10 of the MYPD Methodology states that ‘Costs related to Operation and Maintenance (O&M) will be allowed. The reasonableness of such expenses will be determined by the Energy Regulator on a case-by-case bases. The reasons that Eskom has given and the breaking down of costs to each activity, each unit and each power station gives NERSA comfort that the generation maintenance plan was done properly; however, it needs to be executed properly.

NERSA Adjustments and Reasons

6.2.34 The adjustments for generation maintenance considered the reasonableness of the proposed maintenance and the past results achieved by the Generation Recovery Plan. According to its maintenance plan, particularly its outage plan, there are indications that Eskom is committed to bringing generation stations back into efficient operating plants, which is beginning to yield positive results.

6.2.35 The aim of allowing maintenances cost is to ensure that Eskom conducts maintenance on its plants to comply with the LOPP and to continue with its generation recovery plan. Therefore, allowing maintenance means improving stations' reliability. If we require Eskom to reach a high-performance target, we need to enable it to do so; allowing maintenance costs is one of the ways NERSA can enable Eskom to reach a high-performance target. It should be noted that EAF is not only affected by maintenance, but proper maintenance also produces reliability, and reliability improves availability (EAF). Therefore, with the assumption that Eskom will do efficient maintenance, we can assume that EAF will increase and the UCLF will decrease.

6.2.36 The breakdown maintenance associated with the new plant, Kusile, will be disallowed to the extent set out above. The amounts to be disallowed are: R649m for FY2025/26, R670m for FY2026/27 and R636m for FY2027/28.

Stakeholder Comments

eThekwini Ratepayers and Residents Association

6.2.37 The eThekwini Ratepayers and Residents Association objects to the revenue Eskom applied for due to the following reasons:

- **Inadequate justification for revenue increases:** Eskom's request does not address internal inefficiencies, burdening ratepayers with disproportionate costs.
  <u>NERSA's response</u>
  Adequate justification has been provided, although it was after the submission, and this has been analysed.

- **Ageing infrastructure and lack of proactive maintenance**: Eskom's inability to manage its infrastructure effectively leads to frequent breakdowns and unplanned outages, compounding maintenance costs that Eskom now seeks to recoup from ratepayers without substantive corrective measures.

NERSA's response

Eskom has been saying that its infrastructure is aged, hence the application for funding replacement of old/ageing infrastructure and to do more maintenance to reduce frequent breakdowns. This is supported only if it is done efficiently.

Organisation Undoing Tax Abuse

6.2.38 OUTA has objected to the increases due to the quality and effectiveness of Eskom's generation plant operation and maintenance (O&M) activities. In its view, Eskom should make every effort to improve its performance, quality and value for money with respect to O&M activities.

NERSA's response

Eskom has started with its generation recovery strategy, and it has proven to be improving. An example of the results is the elimination of load-shedding for more than 200 days, which shows improvement in performance.

6.2.39 Eskom should look at the following:

a) Outsourcing power station O&M to more efficient and leaner external operators.

   NERSA's response

   NERSA agrees with outsourcing power station O&M. However, it should be noted that this will be good only if proper contracting is done to ensure all risks fall under the contractor. IPPs are doing this; however, it comes with a high price.

b) Partnering with and outsourcing critical maintenance.

   NERSA's response

   Eskom is currently doing this because it has contracts on and/or it is outsourcing specialised equipment/work.

c) Closing uneconomic power stations.

   NERSA's response

   Eskom is currently working on this, e.g. the Komati Power Station has been shut down.

General public

6.2.40 According to the general public, this increase will not make it possible for the low-income households to afford electricity, and it will deepen the already bad situation regarding affordability.

<u>NERSA's response</u>

NERSA agrees that it will be more expensive to buy electricity. However, maintenance needs to be done to ensure that at least electricity is available and that the economy survives so that all can benefit from it.

Table 26*:* NERSA final decision

Maintenance Opex (R'm)	Application FY2026	Adjustment	NERSA Decision FY2026	Application FY2027	Adjustment	NERSA Decision FY2027	Application FY2028	Adjustment	NERSA Decision FY2028
Gx Total Maintenance Opex	21 742	-649	21 093	20 693	-670	20 023	22 224	-636	21 588

Other Operating Costs

Summary of the application

6.2.41 Other Operating Costs includes all costs involved in the day-to-day running of the business. The licensee's operating costs have considered the importance of driving cost curtailment in line with the turnaround plan to reduce Eskom's cost base. These initiatives are expected to contribute to Eskom's overall financial sustainability.

6.2.42 Other Operating Costs contains all the costs that are not classified as either manpower or maintenance costs. It includes the following operating costs: Contractor Costs, decommissioning expense, environmental expense, Internal electricity revenue consumption, materials expense, net insurance expense, office and site operation costs, operating lease, consulting and travel costs, Other General Expenses and Recovery posting.

6.2.43 Eskom is applying for R14 558m, R14 741m and R15 085m for the 2025/26, 2026/27 and 2027/28 financial years, respectively, as shown in **Table 28** below. This amount is for Generation-regulated business.

Table 27: Eskom application

OPEX Gx (R'm)	NERSA Approved 2025	Application 2026	Application 2027	Application 2028
Other operating costs	4 161	14 558	14 741	15 085
		249,87%	1,26%	2,33%

6.2.44 The table above highlights a significant increase of 249.87% compared to the previous NERSA decision. This increase is driven by the following costs: contractor costs, environmental expense, materials expense, net insurance expense, office and site operation costs, operating lease, consulting and travel costs and other general expenses.

6.2.45 Table 28 below lists all components related to Other Operating Costs, which will be discussed in the analysis section below.

Table 28: Eskom's other operating costs

Other costs Gx (R'm)	Application 2026	Application 2027	Application 2028
Contractor Costs	3 948	4 021	4 039
Decommissioning Expenses	0	0	0
Enviromental Expenses	714	716	579
Internal Electricity Revenue consumption	1 158	1 301	1 429
Material expense	1 406	1 441	1 451
Net insurance expense	4 212	4 355	4 536
Office & Site operation costs	2 414	2 426	2 440
Operating Lease - Consulting & Travel	997	762	916
Other general expenses	592	616	615
Recovery postings	-884	-897	-921
secondary account capitalization	0	0	0
Total Gx Operating Costs	**14 557**	**14 741**	**15 084**

NERSA Analysis

Contractor costs

6.2.46 Contractor costs constitute amounts paid to external service providers mainly for civil, design services (engineering related), drilling services, electrical services and ash handling.

6.2.47 Contractor costs are increasing by 37,47% compared to FY2024/25. The costs are mainly due to Eskom Rotek Industries' (ERI) services, which had low actuals, between R277m and R789m in FY2022/23. The predominant activity performed by ERI under the category of Contractor Costs relates to ash handling activities, cleaning of the ash dams, operation of the slurry plant and waste removal because of plant activities.

6.2.48 Section 10.4.4 of the MYPD Methodology states, 'Expenses must be prudently and efficiently incurred and must be at arm's length transactions'. Eskom has been asked to provide the details of the procurement of ERI services, which will be used in the evaluation of the MYPD6 RCAs.

6.2.49 The increase in contractor costs of 37,47% is not allowed as it is within management's control, should be managed more efficiently and should not be borne by customers. The increase was limited to inflation.

Environmental expenses

6.2.50 This relates to costs incurred in cleaning up the environment, waste management and removal, emptying and removing bins from the site and monthly analysis of water and effluence. This cost is also increasing by a significant amount of 50,63% compared to FY2024/25.

6.2.51 The requested increase is not allowed as the cost is within management's control and should be managed more efficiently. It is, thus, limited to inflationary increase.

Materials expense

6.2.52 This amount represents the costs of stores' materials (excluding food and beverages) that have been transferred from inventory stores for the period. Examples include mill balls, lubricants, gases and chemicals used in plant operations. This account is used to record the cost of purchases of cleaning materials such as detergents.

6.2.53 This cost is also increasing by a significant amount of 59.05% compared to FY2024/25. The cost is within management's control, should be managed more efficiently and the exorbitant costs should not be borne by customers. The increase was limited to inflation.

Net insurance expense

6.2.54 Maintenance and asset renewal are good measures to treat the risk of failures due to an ageing plant. The net insurance expense could increase considering the ageing generation fleet and postponed maintenance activities as these increase plant risks. Eskom's power plants (excluding Koeberg) are insured by Eskom's captive insurance company (Escap).

6.2.55 Insurance costs increased by R1bn in FY2022/23 due to additional units commissioned, as well as the change in the methodology for determining insurance premiums.

6.2.56 Although above inflation (24,69%) compared to FY2024/25 costs, half of these costs will be allowed in consideration of the ageing generation fleet and postponed maintenance activities. This is also in line with the drive to improve Eskom's EAF.

Office and site operations cost

6.2.57 This constitutes mainly of the following components:

- Cleaning materials and services for the plant and offices: Cost of cleaning services rendered by external parties, including cleaning material purchases
- Licence levies for water, National Nuclear Regulator, NERSA
- IT costs, horticultural services, occupational health services, security services, safety gear and equipment.

6.2.58 Office and site restoration's main drivers of the 71,57% increase was due to cleaning material and services costs and sundry licences.

6.2.59 This cost is also believed to be within management's control and should be managed more efficiently. It is, thus, limited to inflationary increase.

Operating lease, consulting and travel cost

6.2.60 This cost is increasing by a significant amount of 51,29% compared to FY2024/25 and consists of the following:

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

6.2.61.1 The cost of bus/taxi services for the transportation of staff/employees

6.2.61.2 Subsidy on local and international travel paid for employees when such employees are away from home on Eskom business locally, including accommodation, meals and incidental costs, such as telephone calls and laundry charges.

6.2.62 Costs related to bus/taxi services for the transportation of staff should not be paid for by customers. Most entities, including the government, have curtailed most expenses related to travel and subsidies. Eskom should adopt similar cost containment mechanisms.

6.2.63 The increase of 51,29% is not allowed as it is within the management's control. It is, thus, limited to inflationary increase.

Other general expenses

6.2.64 Other general expenses include sports and recreation, corporate membership fees, printing, stationery and office telephones and cell phones.

6.2.65 This cost is also increasing by a significant amount of 187,38% compared to FY2024/25.

6.2.66 Most entities have cut down on expenses related to sports and recreation, and Eskom should adopt a similar cost containment mechanism. This requirement is backed by the Guidelines on Cost Containment Measures issued by the National Treasury on 31 August 2023 for the 2023/24 financial year.

6.2.67 The increase of 187,38% is not allowed as it is within the management's control. It is, thus, limited to inflationary increase.

Methodology Used

6.2.68 Section 10.3 of the Methodology states that costs related to Operation and Maintenance (O&M) will be allowed. The reasonableness of such expenses will be determined by the Energy Regulator on a case-by-case basis.

6.2.69 Section 10.4.8 of the Methodology states that other expenses that are not related to the core business of supplying electricity will also be disallowed, and section 10.4.10 further states that other expenses referred to other costs must be unbundled.

Table 29: Stakeholder comments and analysis

Issues Raised by Stakeholders	NERSA Analysis
Increased operational costs: eThekwini Ratepayers and Residents Association are concerned that there are ongoing logistical inefficiencies that contribute substantially to the proposed revenue increases, yet there is	The reasonableness of the costs was assessed to check whether they are related to the core business of supplying electricity.

no robust accountability mechanism to drive down the costs.	
OUTA is of the view that Eskom's application demonstrates inadequate signs of self-discipline in improving its financial and operational performance and efficiency to ensure cost reflectivity.	The affordability of the customers, end users and attracting investments into the energy sector and sustainability of Eskom were considered when assessing other costs.
BUSA is concerned that Other Operating Costs is growing at a rate of 66.62% in FY2026 against FY2025 projections. The portion of the FY2026 increase can be attributed to an abnormal adjustment for a Koeberg Decommissioning Cost deduction of R10 225m in the FY2025 base, the projection for the FY2025 fiscal of R16 664m is still 95.54% greater than the NERSA FY2025 decision (R8 522m). NERSA should insist on transparency, accountability and fiscal discipline in Eskom's cost management to protect consumers from bearing the burden of avoidable costs. The stakeholder is of the view that NERSA should interrogate the underlying drivers of the cost items claimed under the Other Operating Costs category and consider limiting the increases to inflation, particularly given that FY2025 projections are almost double the FY2025 NERSA decision.	NERSA acknowledges the stakeholder's comments. However, Eskom did not consider the NERSA decision as a base as it is of the view that NERSA decisions do not consider current economic conditions and other elements that influence other costs. Only prudently and efficiently incurred costs will be allowed so that consumers do not bear the burden of other costs. Other costs applied for were thoroughly scrutinised and will be limited to inflation to protect customers from a high tariff.
Agri SA suggests that cost saving, management overhaul, and efficiency improvements should be the focus, rather than burdening South African consumers with exorbitant MYPD6 tariff increases.	Only costs related to the core business of supplying electricity will be allowed.
SALGA is concerned that the increase in Other Operating Costs for 2026 is coupled with erratic adjustments in 2027 and 2028, indicating that the costs in 2026 are higher than they should be, given the amounts in 2024 and the reductions in 2025. Even if 2024 is used as a base, inflationary adjustments will take 2026 to below R25bn.	Eskom did not consider the NERSA decision as a base, hence the high increase in other costs.

NERSA's Adjustments and Reasons

6.2.70 The main reason for the steep costs in the first year of the application period is due to Eskom not basing the increases on NERSA's previously approved costs. This is shown in the figure below.

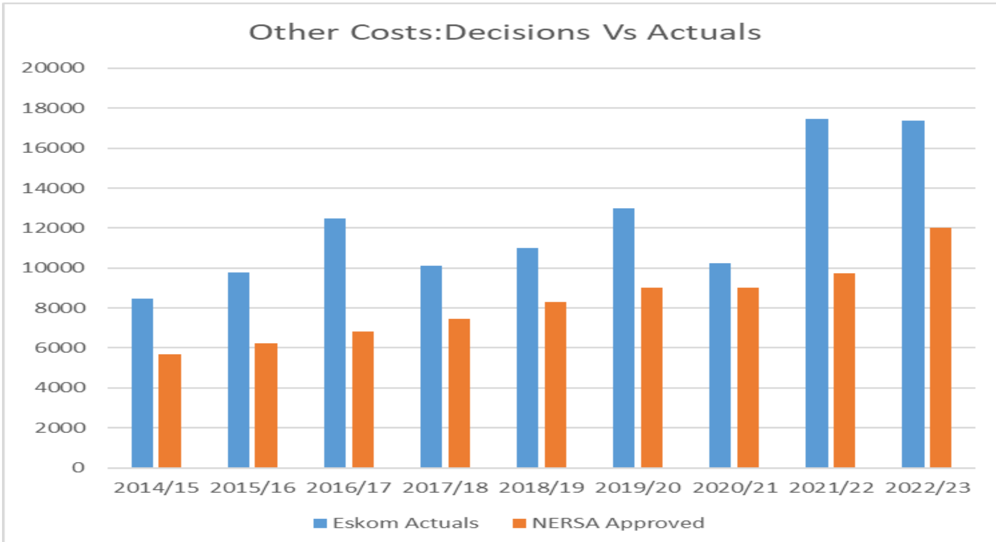

Figure 5: Other costs vs actuals

6.2.71 The above graph contrasts Eskom's other operating costs pattern against NERSA's approved costs from FY2013/14 to FY2021/22. 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 undermines the Energy Regulator's decision.

6.2.72 The figure further highlights Eskom's lack of cost containment measures as some of the costs are within management's control, should be managed more efficiently, and the exorbitant costs should not be borne by customers.

6.2.73 Most entities, including the government, have curtailed most expenses, and Eskom should adopt similar cost containment mechanisms. This requirement is backed by the Guidelines on Cost Containment Measures issued by the National Treasury on 31 August 2023 for the 2023/24 financial year.

6.2.74 Allowing Eskom to pass on these high costs to consumers can have a detrimental impact on the economy, as high electricity prices can hinder economic growth and place a burden on households and businesses.

6.2.75 All other line items will be limited to inflation as the costs are within management's control. An inflationary increase is considered reasonable to cover the rising costs of materials, labour and maintenance, which is vital for operational costs within the electricity generation business.

6.2.76 Furthermore, allowing an inflationary increase in operating costs will ultimately benefit consumers, and it is essential for the functioning of the economy as a whole.

Table 30: Generation other costs decision

Other Opex Gx (R'm)	Application 2026	Adjustments	NERSA Decision	Application 2027	Adjustments	NERSA Decision	Application 2028	Adjustments	NERSA Decision
Other operating costs	14 558	-3 704	10 854	14 741	-3 266	11 475	15 085	-3 009	12 076

Corporate Services

Summary of the application

6.2.77 Corporate overhead costs incorporate those costs that are centrally controlled and are required for the generation, transmission and distribution of electricity. In Eskom's value chain, these costs incorporate the provision of services at a centralised strategic and operational level.

6.2.78 The table below shows that the generation corporate overheads over the MYPD6 application period are R5 527m for FY2025/26, R5 799m for FY2026/27 and R5 946 for FY2027/28. These costs mainly relate to employee benefits, operating costs and depreciation. The corporate costs are allocated to the licensees in accordance with the MYPD Methodology.

Table 31: Generation corporate overhead costs with projections

OPEX Gx (R'm)	Actual FY2023	Projections FY2024	Projections FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Corporate Overheads	1 994	4 479	5 264	5 527	5 799	5 946	6 159	6 389
		124,62%	17,53%	5,00%	4,92%	2,53%	3,58%	3,73%

6.2.79 Eskom's projected costs for FY2023/24 show a substantial increase of 124.62%. This is based on the actual costs of R1 994m for FY2022/23.

The costs are followed by a projected increase of 17.53% in FY2024/25 and then flatten to a single digit increase for the remaining years.

6.2.80 The increases evidenced in the MYPD6 periods are within inflationary expectations. However, this is premised on a FY2024/25 projection that is considerably higher than the FY2024/25 NERSA decision. When the FY2025/26 period is measured against the FY2024/25 decision, a 34.02% increase is evidenced.

Table 32: Generation corporate overhead costs

OPEX Gx (R'm)	NERSA Approved 2025	Application 2026	Application 2027	Application 2028
Corporate Overheads	4 124	5 527	5 799	5 946
		34,02%	4,92%	2,53%

NERSA Analysis

6.2.81 The following are the main costs driving the increase in the first year of the application period:

6.2.82 Other Operating Costs related to the Human Resources Division is escalating by 163.76% from an approved amount of R69m in FY2024/25 to R182m in FY2025/26. This increase is excessive and unjustifiable; therefore, it will be limited to an inflationary increase.

6.2.83 Eskom explained that the main cost driver is the management of onsite medical and wellness centres to ensure the staff is treated immediately when emergencies occur, monitoring employee health and managing external medical claims related to workplace injuries. Legal costs for industrial relation activities are also included in the Other Operating Costs.

6.2.84 Under the Eskom Academy of Learning (EAL) Division – manpower costs for FY2025/26 are increasing by 54.3% from the approved amount of R92m in FY2024/25. The Methodology only allows inflationary increases plus salary betterment for manpower costs. This will, therefore, be adjusted in line with the Methodology.

6.2.85 Under Group Information Technology (IT) Division – all costs related to this section are significantly increasing. The employee benefit costs are increasing from R880m in FY2024/25 to R1000m in FY2025/26, amounting to a 13.64% increase. Other operating expenses are increasing from R947m in FY2024/25 to R1390m in FY2025/26, amounting to a 44.77% increase. Depreciation costs are also significantly increasing by 142.59% with no justification. These increases cannot be allowed as they are too high and should be managed more efficiently. Costs related to Group IT will be limited to inflation increases.

6.2.86 Other operating expenses under the Eskom Treasury Division are considerably increasing by 143,4% in the first year of the application.

6.2.87 Eskom has indicated that the higher other operating expenses in FY2023/24 to FY2025/26 relate mainly to legal fees expected during the current unbundling and legal separation processes being undertaken but should abate in the latter years (from FY2026/27 onward).

6.2.88 Other operating expenses under the Group Finance Controller (GFC) Division are significantly increasing by 84.12% in the first year of the application. Eskom indicated that the above inflation increase in costs over the MYPD6 period is to cater for audit and other consulting fees required for the legal separation of the Generation and Distribution divisions. Provision has been made for specialist services required for initial restructuring costs relating to ringfencing of divisions, assessing and retaining critical capabilities, ensuring a high-performance culture and the establishment and operation of a turnaround management office.

6.2.89 NERSA acknowledges that the costs associated with Eskom's legal separation of the Generation and Distribution divisions are a legislative requirement. These costs will be allowed with the expectation that they would be one-off costs to deal with the legal business separation and that the costs will normalise once the separation is complete.

Approach/Methodology Used

6.2.90 Section 10.4.2 of the MYPD4 Methodology states that *manpower costs should be allowed in accordance with the allowable revenue; any additional expenses over and above what was allowed will be at Eskom's expense, excluding inflationary charges*.

6.2.91 The MYPD Methodology states, 'Costs related to Operation and Maintenance (O&M) will be allowed. The reasonableness of such expenses will be determined by the Energy Regulator on a case-by-case bases.

Stakeholder Comments

6.2.92 Most stakeholders (including SAICA, FAPA, BUSA and OUTA) stated their concern about the high increases proposed by Eskom in other operating costs, including a portion of corporate overhead costs. Another concern raised was the fact that Eskom's proposed increases for MYPD6 were within inflationary expectations; however, this was premised on FY2024/25 projections that are considerably higher than the FY2024/25 NERSA decision. When the FY2025/26 period is measured against the FY2024/25 decision, much higher increases are evidenced.

6.2.93 Furthermore, stakeholders raised concerns regarding the decline in Eskom's workforce, which is accompanied by increases in employee benefit costs above inflation. They further stated that it is difficult to justify salary increases in a scenario where the company is incurring financial losses and then passing these costs onto customers, particularly Megaflex consumers, who are already facing significant affordability challenges.

NERSA Analysis

6.2.94 NERSA acknowledges the stakeholders' comments and will consider the rising employee costs and the corresponding number of employees. NERSA will not allow any unjustified costs related to both employee costs and other operating costs.

NERSA Adjustments and Reasons

6.2.95 A number of the Corporate Division's other operating costs are increasing at levels that are significantly higher than inflation. These are costs believed to be within management's control and should be efficiently managed. Based on stakeholder comments and an overwhelming concern raised regarding affordability, the costs related to corporate other costs will be capped to inflation increases for the three years of the application period, respectively.

6.2.96 Employee benefit costs will be adjusted in line with the requirement of the Methodology. The assessment shows that based on the NERSA-approved amount of R1856m in FY2024/25 when adjusted for inflation of 4,5% and betterment of 2,5%, the NERSA decision will be R1 986m for FY2025/26. For FY2026/27, the amount will be R2 125m after a betterment of 2,6% and inflation of 4.4%. The NERSA decision for FY2027/28 will be R2 221m after considering inflation of 4,4% and betterment of 0.1%.

6.2.97 The adjusted amounts for FY2025/26, FY2026/27 and FY2027/28 ensure that the approved costs are aligned with the actual needs and performance of the organisation, promoting efficiency and cost-effectiveness. This decision ensures that the approved corporate costs are reasonable and justified, address stakeholder concerns and align with the MYPD4 Methodology.

Table 33: Generation corporate costs

OPEX Gx (R'm)	NERSA Approved 2025	Application 2026	Adjustment	NERSA Decision 2026	Application 2027	Adjustment	NERSA Decision 2027	Application 2028	Adjustment	NERSA Decision 2028
Employee benefit costs	1 856	2 488	502	1 986	2 610	485	2 125	2 676	456	2 221
Other operating costs incl Dep	2 268	3 039	669	2 370	3 189	715	2 474	3 270	687	2 583
Total	**4 124**	**5 527**	**1 171**	**4 356**	**5 799**	**1 200**	**4 599**	**5 946**	**1 142**	**4 804**

Conditions for Approval

None.

Other Income

Summary of the application

6.2.98 Other income comprises dividend income, insurance income, operating lease income, sale of scrap and sundry income, management fees, recovery of contracts executed on behalf of subsidiaries, testing conducted in laboratories and sale of energy publications, meal and bus ticket sales and projected grants from National Skills Fund and mandatory grants from the Energy and Water Sector Education and Training Authority (EWSETA).

6.2.99 Eskom states that other income is challenging to forecast with any degree of accuracy. The forecast for the next few years was made based on historical trends, as shown in the table below.

Table 34: Generation other income

Other Income (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Generation Licence Other Income	(2 875)	(243)	(227)	(220)	(230)	(168)	(168)	(168)
Total	**(2 875)**	**(243)**	**(227)**	**(220)**	**(230)**	**(168)**	**(168)**	**(168)**

NERSA Analysis

6.2.100 Under Group Finance Controller (GFC), a management fee is charged to the Eskom subsidiaries for employee benefit expenses of staff secondments. The income in FY2025/26 is R134m and is increasing by 5.2% in FY2027/28 to R141m.

6.2.101 The other income forecast by Eskom is allowed as applied for, as it is aligned with the historical trends.

Table 35: Generation other income

OPEX Gx (R'm)	NERSA Approved 2025	Application 2026	Application 2027	Application 2028
Other Income	-243	-220	-230	-168
Adjustments		0	0	0
NERSA Decision		-220	-230	-168

RESEARCH, TESTING AND DEVELOPMENT

Summary of the Application

6.2.102 Research, Testing and Development (RT&D) is mandated to perform applied technical research and provide specialist technical consulting and specialist technical testing services. Through these services, RT&D not only enhances Eskom's operational efficiency but also contributes to the strategic decision-making processes that will aid Eskom in achieving its goals and maintaining sustainability amidst the rapidly changing energy landscape.

6.2.103 To further support the line divisions, RT&D has adopted a 60:30:10 effort level principle whereby 60% represents RT&D efforts to support line divisions with the operational recovery initiatives. The 30% is representative of RT&D's efforts to assist with preparing for a liberalised market with a particular focus on the Just Energy Transition. The 10% is illustrative of RT&D's efforts to assist Eskom to remain competitive in the long-term by developing new capabilities to compete in new markets through innovation and agility.

Research Mandate

6.2.104 To achieve its mandate, RT&D provides the following services to Eskom's line divisions:

6.2.104.1 Conduct research that aligns with the National Energy Regulator of South Africa's (NERSA) MYPD Methodology.

6.2.104.2 Provide technical investigation, specialised consulting, testing and analytical service functions.

6.2.104.3 Showcase and pilot cutting-edge technologies that represent the next horizon in energy solutions.

6.2.104.4 Provide specialised technical skills transfer on new technologies.

Research Statement of Purpose

6.2.105 The major focus of the research function of Eskom RT&D is on business needs (that is, operational, applied, strategic, and basic research) and a minor focus on futuristic research.

RT&D Research Portfolio

6.2.106 Eskom RT&D has been delineated to cover four distinct research programmes: i) Generation; ii) Transmission; iii) Distribution; and iv) Cross-cutting. These programmes consist of operational/applied, strategic (pilots and demonstrations), basic/futuristic research, and development. The programmes have been formulated into the respective Research Technical Committees (RTCs).

Analysis of the Application

RT&D costs

6.2.107 Eskom is applying for R146m, R152m and R159m for FY2025/26, FY2026/27 and FY2027/28 respectively, as seen in the **Table 36** below.

Table 36: Research testing and development costs

Research, Testing and Development	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
RTD cost	139	146	152	159
Total	**139**	**146**	**152**	**159**

6.2.108 The research projections are further based on the input of key internal and external stakeholders in various fora. This includes the annual stakeholder review that is convened at the behest of NERSA. In the execution of its mandate, RT&D is required to comply with specific acts and regulations governing research areas in which investments are made, expenditure incurred gaining intellectual property that emanates from such research and development and patents that are registered.

The Approach/Methodology

Alignment with MYPD criteria

6.2.109 The projected spend for FY2023/24 and FY2024/25, as well as the application for FY2025/26, FY2026/27 and FY2027/28, result in continued alignment of the following NERSA criteria:

i) Those that will result in improved efficiency
ii) Those that will result in extended plant life
iii) Those that will result in lower operating costs
iv) Those that will result in a better load or power factor
v) Those that will result in a better understanding of load behaviour
vi) Those that relate to the design, construction, selection and operation of projects in the build plan or demo plant of those technologies that might form part of a future build plan.

6.2.110 In addition, the following environmental projects are categorised, where applicable:

6.2.110.1 Those related to developing, designing, selecting and operating renewable energy

6.2.111 RT&D is a significant aspect of continuous improvement and optimisation in energy provision to South Africans.

Adjustments and Reasons

6.2.112 In the main application, Eskom has not shown the amount it requested for Research, Testing and Development as a line item in terms of the MYPD Methodology; therefore, there is no adjustment.

6.2.113 The revenue amount requested by Eskom for FY2025/26, FY2026/27 and FY2027/28 will be split amongst three Eskom divisions in the following manner:

Support line divisions	60%
JET programme	30%
Other research	10%

Any Conditions of Approval

6.2.114 Due to Eskom giving reasons that it is undergoing restructuring, that more research on new technology is needed, and the expenditure on research projects it will undertake, Eskom can be allowed the revenue it has requested.

Summary of Operating Costs

6.2.115 The **Table 37** below shows a summary of the operating cost decision. It shows total operating costs allowed of R47.4bn for FY2025/26, R47.9bn for FY2026/27 and R50.8bn for FY2027/28 after effecting the adjustments.

Table 37: Summary of operating costs

OPEX Gx (R'm)	NERSA Approved 2025	Application 2026	Adjustments	NERSA Decision	Application 2027	Adjustments	NERSA Decision	Application 2028	Adjustments	NERSA Decision
Employee benefit costs	10 899	14 281	-2 679	11 602	14 858	-2 508	12 350	15 176	-2 273	12 903
Maintenance	13 910	21 742	-649	21 093	20 693	-670	20 023	22 224	-626	21 598
Other operating costs	4 161	14 558	-3 704	10 854	14 741	-3 266	11 475	15 085	-3 009	12 076
Corporate Overheads	4 124	5 527	-1 171	4 356	5 799	-1 200	4 599	5 946	-1 142	4 804
Other income	-243	-220	0	-220	-230	0	-230	-168	0	-168
Total	**32 851**	**55 888**	**-8 203**	**47 685**	**55 861**	**-7 644**	**48 217**	**58 263**	**-7 050**	**51 213**

6.3 PRIMARY ENERGY

Production Plan

Summary of the application

6.3.1 Eskom submitted Energy Wheels that balance the forecast sales and the supply options, including pumping, wheeling and energy losses for both transmission and distribution systems.

Table 38: Energy breakdown per technology

Electricity Output (GWh)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Power Sent Out by Eskom Station, Gwh (net)	191 307	183 900	186 036	177 260	170 156	145 802
Coal Fired Stations (incl, Pre-Comm) GWh (net)	171 131	167 177	170 108	159 704	149 556	126 241
Hydroectric stations. GWh (net)	3 060	945	832	779	616	830
Pumped Storage Stations, GWh (net)	4 081	4 793	4 522	4 242	4 055	4 188
Gas Turbines Stations, GWh (net)	3 018	2 539	1 266	1 266	1 266	1 266
Wind Energy, GWh (net)	214	314	307	304	304	304
Nuclear Power Station, GWh (net)	9 803	8 131	9 001	10 965	14 359	12 973
IPP purchases, GWh	17 957	22 972	23 856	31 364	35 214	57 259
Wheeling, GWh	2 904	2 152	2 826	2 723	2 723	2 831
Energy Imports fom SADC countires, GWh	8 654	9 295	9 776	6 601	6 449	8 573
Total Gross Energy sent Output, GWh	*220 822*	*218 320*	*222 493*	*217 948*	*214 543*	*214 464*
Less Pumping	5 504	6 469	5 901	5 539	5 294	5 464
Total Net Production, GWh	**215 318**	**211 851**	**216 592**	**212 409**	**209 249**	**209 000**

6.3.2 The contribution of energy from coal stations is declining over the application period while the RE contribution is increasing. However, Eskom has adopted the strategy of not shutting down any coal station before 2030 to reduce the risk of load-shedding. Power stations, such as Tutuka, which are operating below capacity due to deferred maintenance, will contribute to higher operational costs (Tutuka's EAF at 25,78% in FY2022/23). Therefore, the delay in shutting down the units will require additional funds to maintain and operate the aged units.

6.3.3 OCGT generation is flat across the application horizon at 6% Load Factor (LF), equating to 1 266GWh. This is a decline in the LF compared to the MYPD5 period. Eskom has indicated that even though the fleet performance is operating at the Energy Availability Factor (EAF) of 63% as at September 2024, the OCGT utilisation is operating around the LF of 6.3%. This highlights that even though the fleet performance is improving, OCGTs are still required during the morning and afternoon peak hours, particularly given the increasing penetration of non-dispatch generation, such as solar, which becomes unavailable during peak hours.

6.3.4 Eskom further performed a stress-test on the production plan, by testing a higher demand, a declining EAF and delays in the Commercial Operation (CO) dates of the REIPP program. The stress-tested plan resulted in the OCGT LF of 25%, 14% and 6.9% in FY2024/25, FY2025/26 and FY2026/27, respectively. Considering the above, Eskom emphasised that the 6% LF applied for is in fact a moderate projection.

Table 39: Projected plant performance for the Eskom fleet

Generation Technical performance (%)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Energy Utilisation Factor (EUF)		79	72	66	62	52
Energy Availability Factor (EAF)	56.5	56	61	63	64	65
Planned Capability Loss Factor (PCLF)	10.4	11.5	10.5	10.5	10.5	10.5
Unplanned Capacity Loss Factor (UCLF)	31.5	31.1	27	25	24	23
Other Capacity Loss Factor (OCLF)	1.6	1.4	1.5	1.5	1.5	1.5

6.3.5 Eskom still cites the reason for the deteriorating performance of its coal fleet as being due to the delay by government to build new capacity in the late 90s, resulting in the need for the over-utilisation of the coal fleet and the delay in performing the required maintenance. This, combined with financial constraints due to the receipt of sub-cost-reflective regulated revenues, resulted in Generation unable to implement most of the mid-life refurbishments, which ensure that the performance of the ageing fleet is maintained.

6.3.6 The Medupi, Kusile and Ingula's new build programmes were meant to provide much-needed relief to the coal fleet. However, they had severe design challenges, which Eskom attributed to having limited time to plan and finalise the designs.

6.3.7 Eskom indicates that the debt relief support from the National Treasury to alleviate the immediate impact of sub-cost-reflective regulated revenues has allowed the early ordering of long-lead spares for outages, which is starting to result in improved maintenance and, therefore, improved plant performance. Eskom has further indicated that the improvement of staff morale has gone a long way toward improving the plant performance.

Approach/Methodology Used

6.3.8 Section 7 of the MYPD Methodology states the following.

Section 7.1: *Eskom must furnish the Energy Regulator with the risk adjusted production plan and the energy wheel that is aligned to the forecasted sales above to be reviewed and approved by the Energy Regulator.*

Section 7.2: *The energy wheel diagram for each year of the MYPD must reflect all generation sources together with the power purchased from Independent Power Producers (IPPs) and international purchases.*

Section 7.3: *The plan shall be adjusted accordingly when the sales volumes are adjusted to ensure alignment.*

Stakeholder Concerns

6.3.9 Stakeholders are concerned with the proposed LF of 6% for OCGTs. They are further concerned about the continued use of coal plants, which have adverse impact on the environment and people living close to the coal plants.

Eskom Responses

6.3.10 Eskom has indicated that the projection of the LF of 6% for OCGTs is to ensure sufficient flexibility in the energy mix to deal with the increase in RE technologies that are intermittent in their nature. Eskom further highlighted that although the plant performance is improving, the system is still very tight in terms of the supply's ability to meet demand and ensure that load-shedding is completely done away with.

6.3.11 Eskom further indicated that the reason for keeping the old coal power plants that were due to be shut down was to ensure system adequacy. Eskom is presently counting over 250 days without load-shedding as system adequacy has been made a reality by the continued operation of these coal plants.

NERSA Analysis

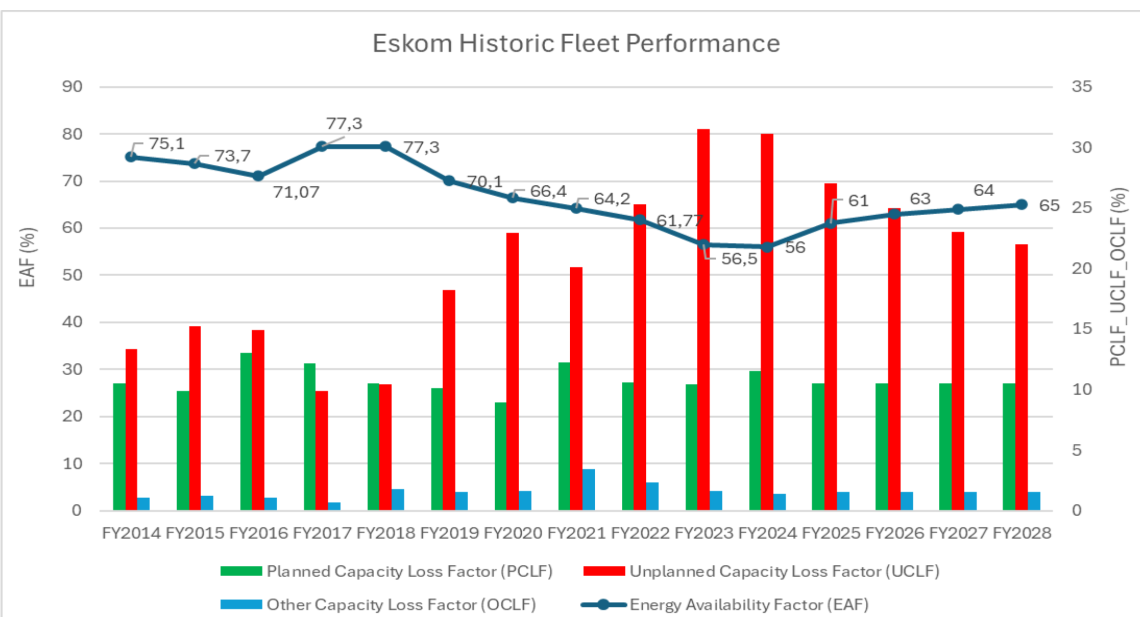

Figure 6: Historic**al** plant performance of the Eskom fleet

6.3.12 Eskom will operate costly generation capacity over the MYPD6 period. Eskom's application excludes any adjustments to available plant capacity to cater for reduced loading. For example, generation output is shrinking by almost 35% during the period; however, costs continue to escalate. Good performing stations such as Medupi, Lethabo and Matimba contribute to the higher EAF of 62.7%, which Eskom has achieved to date.

6.3.13 The older stations that are not performing at acceptable levels, such as Tutuka, Duvha, Majuba, Matla, Kendal, Arnot and Kriel, will need to be taken offline to deal with the legacy issues to normalise these plants. Subsequently, normal philosophy maintenance and acceptable operating practices can maintain the acceptable level of performance of these plants. Overall, NERSA emphasises that to be deemed to be an efficient operator, Eskom needs to get the fleet back to the overall EAF performance of 75%.

Stakeholder Comments

6.3.14 SAFCEI believes that using old, inefficient, and polluting coal-fired power stations must be discontinued and replaced with appropriate alternative technology. Old coal is a double cost to the communities within the air pollution fallout zone. They pay for the electricity, and they pay through poor health.

NERSA Analysis

6.3.15 The comment regarding health concerns is noted. However, it must be highlighted that the decline in the use of coal and the increase in the use of renewables is clear over the MYPD 6 period; the transition is underway. It must further be noted that, at present, coal-fired power stations provide a range of functions and benefits required for grid stability that current renewable technologies do not. Therefore, more time is required to replace the entire coal fleet with appropriate alternative technologies, and the proposed technologies must include dispatchable plants and plants that will provide flexibility; otherwise, there is a real risk of collapsing the grid.

NERSA Adjustments and Reasons

6.3.16 Section 15(1)(a) of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the ERA') highlights that the tariffs set by the Regulator:

must enable an efficient licensee to recover the full cost of its licensed activities, including a reasonable margin or return.

6.3.17 Eskom is, therefore, only entitled to efficient costs. Eskom is projecting an EAF ranging from 63% to 65% for the application period. However, according to the VGBE report of August 2023, international benchmarks indicate that the Eskom fleet should be operating at 78%.

6.3.18 The current Eskom performance level of EAF of 62.7% is a good improvement from the EAF of 57% as at April 2023. However, there is room for improvement, and Eskom needs to maintain a higher standard of performance and efficiency. The following performance standard is set for Eskom:

- An EAF of 75% over the application period.

6.3.19 The performance standard set is premised on section 15(1)(a) of the ERA, i.e. that Eskom can only be allowed its cost if it is an efficient licensee. The full costs will, therefore, be allowed on condition of efficient performance levels. NERSA has determined that the efficient performance level is an EAF of at least 75%. The PCLF under this scenario is not adjusted and the OCGTs are set at 4% because of the required higher availability of the coal fleet.

Table 40: Required performance

Required Technical performance (%)	Decision FY2026	Decision FY2027	Decision FY2028
Energy Availability Factor (EAF)	75	75	75
Planned Capability Loss Factor (PCLF)	10.5	10.5	10.5
Unplanned Capability Loss Factor (UCLF)	13	13	13
Other Capability Loss Factor (OCLF)	1.5	1.5	1.5

The Rationale for Setting a Target EAF of 75%

6.3.20 The EAF is the outcome that depends on the reduction of the unplanned Capability Loss Factor (UCLF). The desired outcome is for the efficient use of the assets, which means that they need to be available and functional at least 75% of the time. Anything below 75% EAF is deemed to be an inefficient use of the assets.

6.3.21 Therefore, NERSA expects Eskom to improve its efficiencies, as reflected by an acceptable Energy Availability Factor (EAF). NERSA is completely justified in seeking an improvement in the EAF as poor performance has many negative consequences, including higher costs and load-shedding.

Eskom, in its application, lists the following performance figures, shown in Table 41 below.

Table 41: Generation technical performance

TABLE 6: GENERATION TECHNICAL PERFORMANCE								
Gx Technical performance (%)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Energy Availability Factor (EAF)	56.5	56	61	63	64	65	66	67
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	25	24	23	22	21
Other Capacity Loss Factor (OCLF)	1.6	1.4	1.5	1.5	1.5	1.5	1.5	1.5

6.3.22 The EAF figures of less than 60% are poor and have resulted in load-shedding in the past. The levels above 60% are better; however, these EAF figures result in the continued use of expensive OCGTs, which should be rightly set at 1%, as in the past when the Eskom coal fleet was operating efficiently above 75%.

6.3.23 As stated above, it must be noted that the Medium-Term System Adequacy Outlook (MTSAO) of 2024 highlights that the system is not fully adequate when considering an EAF ranging between 61% and 64% over the application period. These levels guarantee elevated use of OCGTs. Thus, NERSA must require Eskom to set a higher target.

6.3.24 Eskom has stated that some of its power stations achieve levels between 70% and 85%, currently. Therefore, these levels are not out of reach.

6.3.25 NERSA mandates Eskom to achieve an average EAF of 75%. However, this target should not compromise maintenance activities, which are set at 10.5% for the period and must remain unaffected. The primary issue is the Unplanned Capability Loss Factor (UCLF), which is significantly higher than international standards. Therefore, Eskom must prioritise reducing the UCLF to below 13%. In fact, a World Energy Council[1] report puts the UCLF figures proposed by Eskom in the lowest (poorest performance) 10 percentile of 770 units worldwide. This is not efficient. Therefore, it is reasonable to set an acceptable minimum standard.

6.3.26 In previous years, a significant portion of Eskom's high Unplanned Capability Loss Factor (UCLF) was attributed to sabotage, which Eskom asserts is no longer an issue. Consequently, it is now entirely within Eskom

[1] Performance of Generating Plant: Managing the Changes by World Energy Council 2008

management's control to reduce the UCLF and achieve the target EAF of 75%. This can be achieved by effectively managing boiler water quality, ensuring coal quality, and adhering to proper operating procedures. Eskom can feasibly meet this target.

6.3.27 The higher EAF will result in a lower Energy Utilisation Factor (EUF), which is required to ensure that the operating plant operates at optimal load and, thus, potentially achieves longer life, requires less maintenance, and results in fewer breakdowns. In turn, this will result in less trips and therefore less starts and lower fuel oil usage.

6.3.28 The ERA requires NERSA to enable an efficient licensee to recover its full cost and a reasonable margin. Eskom will be allowed costs that are in line with the efficient performance level of an EAF as required.

6.3.29 Under the Sales section, the standard tariff sales have been adjusted upwards by 6 476GWh, 8 941GWh and 10 706GWh for FY2025/26, FY2026/27 and FY2027/28, respectively. Furthermore, an adjustment to the Generation from non-Eskom generation facilities (REIPPP) to the extent of 205GWh, 222GWh and 221GWh over the application period from a BW5 plant that did not reach financial close and an amount of 13TWh from BW8 in FY2027/28, which will not materialise.

6.3.30 The utilisation of the coal fleet ranges between 72%, 67% and 55% over the application period. This is welcomed as the coal fleet has been operating at EUF of over 80% for a long time, which has been detrimental to the performance of the fleet. Given that the performance imposed on Eskom is higher than the production plan in the application, there is more than enough room in the coal fleet for additional generation.

6.3.31 Furthermore, considering the higher standard set for Eskom fleet performance, the OCGT usage will be reduced slightly to 4%. The OCGTs are set at this level to ensure that the much-needed flexibility in the fleet is available, given the higher penetration of RE technologies in the energy mix.

6.3.32 The increase in sales projection, the reduction of the OCGT LF to 4% over the application period as well as the reduction in REIPPPP contribution over the application period requires an increase in energy sent out from coal generation by 7 591GWh, 10 073GWh and 25 591GWh for FY2026, FY2027 and FY2028 respectively.

6.3.33 Changes in the production plan will result in changes in Primary Energy. Requirements for additional energy production from the coal fleet will result in an increase in coal usage, water usage, fuel oil usage and sorbent usage. Eskom was requested to provide a revised Production Plan and costing but this was not deemed feasible by them. Therefore, the approach taken was to use the average coal cost from the existing Production Plan and increase the allowable revenue for coal accordingly. The difference which may occur will, therefore, be dealt with in the RCA. Eskom indicated that it had space to increase the coal loading by about 7 000MW, so capacity should not be an issue.

Table 42: Primary energy costs

Total Generation Primary Energy (Rm)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Coal Usage	63 069	71 979	83 238	93 653	96 537	89 640
Water Usage	2 332	2 573	3 368	3 936	3 988	4 359
Fuel and Water Procurement department cost	274	295	334	351	368	384
Coal Handling	2 293	2 419	3 090	3 314	3 469	3 633
Water Treatment	669	848	1 004	1 014	986	1 029
Sorbent Usage	186	366	361	455	477	449
Sorbent Handling	6	17	23	23	24	20
Fuel Oil Usage	8 807	8 932	9 845	10 745	11 086	11 485
Nuclear	674	649	840	982	1 519	1 648
OCGT Usage	21 355	19 152	10 059	10 548	11 029	11 531
Coal and Gas (Gas Fired)	7	10	9	9	10	11
Eskom Generation Primary Energy Costs	**99 672**	**107 240**	**112 171**	**125 030**	**129 493**	**124 189**

6.3.34 The main drivers of the Primary Energy Costs are coal usage, fuel oil usage and OCGT usage, which contribute approximately 74%, 8.5% and 8.4%. respectively.

Approach/Methodology Used

6.3.35 Section 12.1 of the MYPD Methodology states the following.

In considering the allowable primary energy costs, the Energy Regulator will consider the most appropriate generation mix that can be achieved practically to the best interest of both the customer and the supplier.

Table 43: Summary of the decision – primary energy

Total Generation Primary Energy (Rm)	Application FY2026	Adjustment FY2026	Decision FY2026	Application FY2027	Adjustment FY2027	Decision FY2027	Application FY2028	Adjustment FY2028	Decision FY2028
Coal Usage	93 653	2 024	95 677	96 537	3 952	100 489	89 640	15 851	105 491
Water Usage	3 936	225	4 161	3 988	322	4 310	4 359	1 060	5 419
Fuel and Water Procurement department cost	351	0	351	368	0	368	384	0	384
Coal Handling	3 314	-625	2 689	3 469	-655	2 814	3 633	-685	2 948
Water Treatment	1 014	-316	698	986	-257	729	1 029	-268	761
Sorbent Usage	455	26	481	477	39	516	449	110	559
Sorbent Handling	23	0	23	24	0	24	20	0	20
Fuel Oil Usage	10 745	-1 971	8 774	11 086	-2 040	9 046	11 485	-2 123	9 362
Nuclear	982	0	982	1 519	0	1 519	1 648	0	1 648
OCGT Usage	10 548	-3 516	7 032	11 029	-3 676	7 353	11 531	-3 844	7 687
Coal and Gas (Gas Fired)	9	0	9	10	0	10	11	0	11
Eskom Generation Primary Energy Costs	**125 030**	**-4 154**	**120 876**	**129 493**	**-2 314**	**127 179**	**124 189**	**10 101**	**134 290**

Coal Burn

Summary of the application

6.3.36 The existing MYPD4 Methodology requires the Energy Regulator to approve the coal benchmark price (i.e. average R/ton) per contract type (Cost-Plus, Fixed-Price, Medium-Term and Short-Term) and Alpha for each contract type in the final MYPD decision.

Coal Purchases

[redacted]

Table 44: Coal purchases – all contracts

[redacted]

6.3.38 It should be noted that coal volumes are decreasing by 34% cumulative for the application period. However, the cost to purchase the reduced volumes is increasing by approximately 5%.

Coal burn

[redacted]

6.3.40 **Error! Reference source not found.** below shows the historical and projected coal burn for all contracts.

Table 45: Coal burn – all contracts

Coal Burn Contracts	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028
Coal Burn (Ktons)	104 871	110 479	102 874	101 030	104 491	98 254	92 011	77 411
Coal Burn (Rm)			63 069	71 979	83 238	93 653	96 537	89 640
Energy Sent-Out (GWh)	177 818	182 463	170 318	165 766	167 149	159 704	149 556	126 241
Energy Availability	60	57	52	52	58	61	62	63
%Increase/Decrease		5%	-7%	-2%	3%	-6%	-7%	-19%

6.3.41 It should be noted that coal volumes are decreasing by 32% cumulative for the FY2025/26 to FY2027/28 period, but the cost of purchasing lesser volumes has increased by approximately 6%.

Approach/Methodology Used

6.3.42 The MYPD Methodology states the following:

Section 12.2.1: *The Energy Regulator will approve the coal benchmark price (i.e. average R/ton) per contract type (Cost Plus, Fixed Price, Medium-Term and Short-Term) and Alpha for each contract type in the final MYPD decision.*

Section 12.2.2: The R/ton coal price and R/ton/km transport cost (rail and road) shall be escalated using the formula in the contracts. Contract parameters (mining input costs like steel, labour, diesel, spare parts, rubber, electricity and tyres) in the indexation formula shall be adjusted using the industry accepted level of inflation available in the public domain.

Section 12.2.3: *Future coal procurement will be informed by the long-term coal procurement strategy that will be submitted to the Energy Regulator at the time of MYPD application. This strategy should demonstrate how Eskom will purchase least cost coal.*

Section 12.2.4: *The forecasts indicated below shall be submitted together with the MYPD application:*

a. *Coal volumes burnt per station, per contract type and per supplier.*
b. *Coal volumes purchased per station, per contract type and per supplier.*
c. *Coal stockpiles tons per station.*

d. Coal costs (R/ton delivered) per station, per contract type and per supplier.
e. Coal quality per station (CV, burn rate, ash content) and per supplier.
f. Road transport costs for each station: tons moved, kilometres travelled and payment rate.
g. Rail transport costs for each station: tons moved, kilometres travelled and payment rate.
h. Price escalations indices (electricity, diesel, mechanical spares, labour, tyres, etc.) for mining and transport for each year of the MYPD.
i. Start date and expiry date of each coal contract per power station.

Stakeholder Concerns

6.3.43 The majority of the stakeholders do not support the revenue application and cite the following key concerns:

- Eskom's coal dependency
- Calls for renewable energy
- Criticism of Eskom's Management and tariff increases
- Corruption and oversight
- Environmental concerns
- Future of Eskom and consumer impact.

Eskom Justification

[redacted]

6.3.45 Furthermore, according to the production plan, at an average EAF of 52%, Eskom coal power stations could produce 165 766GWh in FY2023/24. The estimated projected EAF for FY2025/26 is 61% and the coal plants are estimated to produce an average of 159 704 GWh of energy. The coal plants should, therefore, be able to achieve these projections unless there are unprecedented unplanned outages.

NERSA Analysis

6.3.46 Based on the MYPD4 Methodology, the following coal purchases analysis were made per contract type:

Coal purchases

ST/MT contract

[redacted]

Table 46: ST/MT and uncontracted coal purchases

[redacted]

Cost-Plus contract

[redacted]

Table 47: Cost-plus coal purchases

[redacted]

Fixed price contract

[redacted]

Table 48: Fixed price coal purchases

[redacted]

6.3.50 The sourcing of more coal from the cost-plus and fixed price contracts is welcomed as these contracts are cheaper than the short-term and medium-term contracts. The use of fewer ST/MT contracts from the FY2025/26 to FY2027/28 period is also welcome, as these contracts are more expensive, and this indicates that less coal will be purchased at spot price.

6.3.51 In summary, Eskom, in its application, indicates the coal volume purchases over the application period, as shown in the table below.

Table 49: Coal purchase volumes

[redacted]

6.3.52 This is not the coal volume used in the revenue determination from the actual coal burn volumes in the Production Plan. The difference is either added to or subtracted from the stockpile.

6.3.53 The table below shows the proposed energy from coal-fired power stations. Therefore, the resulting coal burn volumes and value are based on each power station's costs, which are different from the average figures above.

Table 50: Production plan coal burn volumes and values

[redacted]

Coal burn

ST/MT contract

6.3.54 Approximately 37% of the coal burnt is from ST/MT contracts. The coal burn volume for ST/MT contracts is projected to increase by 14% in FY2025/26 and decrease by 11% in FY2026/27. The increase is due to the Duvha Power Station planned with the ST/MT contract during FY2025/26. However, in total, there has been a decline in the use of ST/MT contracts, driven by the decline in the energy output from the coal fleet. Table 51 below shows the historical and projected coal burn for ST/MT contracts.

Table 51: ST/MT coal burn

[redacted]

Cost-Plus contract

6.3.55 Approximately 38% of the coal burnt is from cost-plus contracts. The coal burn volume is projected to decrease by 20% cumulative from FY2024/25 to FY2025/26. Table 52 below shows the historical and projected coal burn for cost-plus contracts.

Table 52: Cost-plus coal burn

[redacted]

Fixed price contract

6.3.56 Approximately 25% of the coal burnt is from fixed price contracts. The coal burn volume is projected to decrease by 55% cumulative from FY2024/25 to FY2025/26. Table 53 below shows the historical and projected coal burn for fixed price contracts.

Table 53: Fixed-plus coal burn

[redacted]

6.3.57 The coal burn is projected to decrease by approximately 32% cumulative from FY2025/26 to FY2027/28 period. This is welcome as consumption is expected to decrease from coal-fired power stations.

Coal stock days

6.3.58 Eskom is projecting and applying for coal stock days of 84 days, 83 days, and 84 days for the FY2025/26, FY2026/27 and FY2027/28 revenue application. The closing coal stock days were 65 days and 85 days for FY2022/23 and FY2023/24, respectively.

6.3.59 According to the Opera Assessment Report, Revision 2 of August 2023, live piles for more than 10 days and strategic piles for more than 20 days are necessary to ensure reliable running of a coal-fired power station.

6.3.60 The Grid Code prescribes minimum stock levels of 20 days. It must be highlighted that the stock days indicated in the Grid Code are a minimum that the utility must keep. After the coal shortage challenges faced in 2008, Eskom undertook a study with different scenarios to ascertain the optimum stock days per station. The days considered in the application are an outcome of that study.

Coal quality

6.3.61 Eskom indicates that managing the quality and quantity of Eskom‘s coal supply is becoming more challenging, and the implications thereof include the reducing calorific value of coal. This challenge introduces inefficiencies in the system, which will require more coal to be burnt to deliver a unit of electricity.

6.3.62 According to Opera Assessment Report Revision 2 of August 2023, Lethabo Power Station has never received coal consistent with design quality. The heating value is consistently below the design coal quality of 16.41 MJ/kg, and the moisture content is above the design coal level of 10.5%. As a result, the plant experiences lower plant efficiency and higher coal flow rate per MWh produced than design. The latter stresses the mills and adds more dust loading on the ESP. So, the impact due to low coal quality is both direct and indirect.

6.3.63 Furthermore, the desktop assessment conducted on the coal quality report of FY2022/23 depicts that there are power stations that received coal with low calorific value, which falls outside the contracted calorific value specification.

Burn rate

6.3.64 The burn rate ranges between 0.59 and 0.62 and increases during the application period. This indicates that more coal is being burnt to produce a unit of energy (kg/kWh). **Table 54** below shows the historical and projected burn rate for all contracts.

Table 54: Burn rate

Burn Rate	**FY 2021**	**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**	**FY 2028**
Burn Rate (kg/kWh)	0,60	0,61	0,59	0,60	0,61	0,62	0,62	0,61
Coal Burn (Ktons)	104 871	110 479	102 874	101 030	104 491	98 254	92 011	77 411
Energy Sent-Out (GWh)	177 818	182 463	170 318	165 766	167 149	159 704	149 556	126 241

6.3.65 According to the Energy Information Administration (EIA) of the United States, the annual average amounts of fuels used to generate one kWh of electricity by US electric utilities and IPPs in 2022 for coal-fired power stations was 0.52kg/kWh. The research report further acknowledges that the coal burn rate can change over time due to various factors, which include boiler ageing, wear and tear, change in coal quality, operating conditions, maintenance and upgrades.

6.3.66 The rate of change of coal-burn rate over time can vary depending on the specific power plant, boiler design and operating conditions. **Table 55** below depicts the acceptable general guideline.

Table 55: Burn rate change guideline

Percentage Increase	Period	Comments
1-2 %	Per year	Relatively normal for an ageing boiler.
5-10 %	5-10 Yrs	May need for maintenance, upgrades, or performance optimization.
› 10 %	Per year	Significant decline in boiler efficiency or a problem with coal quality.

Stakeholder Comments

6.3.67 The eThekwini Ratepayers and Residents Association (ERRA) objected to the Eskom application. It indicated that Eskom’s dependence on costly coal procurement and ongoing logistical inefficiencies contributes substantially to these proposed revenue increases, yet there is no robust accountability mechanism to drive down these costs.

6.3.68 ERRA further indicated that the procurement inefficiencies, particularly in coal supply, reflect a lack of strategic management that goes unaddressed in this application. It stated that ratepayers cannot continue to subsidise Eskom’s imprudence and inefficiency.

6.3.69 OUTA stated that coal and coal transport costs form a major part of the cost of primary energy. It stated that Eskom’s MYPD6 revenue application does not demonstrate adequate attention and commitment to the following:

i) Reducing Eskom’s over-dependence on coal and rising coal costs.
ii) Replacing old Eskom coal power stations with cleaner, lower-cost options.
iii) Improving coal procurement management and associated skills.
iv) Improving coal transport management and bringing coal transport costs under control.
v) Improving coal quality management.
vi) Reducing corruption in coal procurement.
vii) Reducing coal theft.

NERSA Analysis

6.3.70 NERSA has benchmarked the unit cost of coal costs and has found them to be lower than the export rate. NERSA has further made adjustments on the basis of burn rate, which deals with aspects of procuring poor-quality coal.

NERSA Adjustments and Reasons

6.3.71 Under the production plan section, performance targets of EAF of 75%, UCLF of 13% and PCLF of 10.5% have been set for Eskom over the application horizon. Furthermore, Eskom has been given a target of achieving higher sales than what they projected in the application.

6.3.72 Projected volumes from all contracts are adjusted to increase coal generation by 7 591GWh, 10 073GWh and 25 591GWh in FY2025/26, FY2026/27 and FY2027/28, respectively. This is to take into account the increased projected sales, the energy removed from OCGTs each year, the energy removed from a project in BW5, and the removal of energy from BW8 in FY2027/28. The coal costs are further adjusted by setting the burn rate at an average of 0.60 kg/kWh as an efficient target.

6.3.73 The burn rate has been adjusted to 0.6kg/kwh because of the improved availability and performance of the more efficient stations. Eskom achieved this figure recently and, therefore, it is considered feasible.

6.3.74 Adding the extra energies changes the production plan from the production plan in the table above to **Table 56** below:

Table 56: Revised production plan figures

[redacted]

6.3.75 This results in an allowable revenue for coal of R95 677m for FY2025/26, R100 498m for FY2026/27 and R105 491m for FY2027/28.

6.3.76 The coal benchmark figures to be applied in the PBR formula in the RCA are given below.

Table 57: Alpha per contract type

Contract Type	Alpha
Cost Plus	0,95
Fixed Price	0,95
Short Term and Medium Term (ST/MT)	0,9

6.3.77 The coal benchmark R/ton price that will be applicable for RCA assessment will be set as applied by Eskom, as shown in **Table 58** below.

Table 58: Benchmark R/ton for use in RCA processing

[redacted]

Conditions for Approval

6.3.78 Eskom must operate within the set coal volumes and set coal cost targets. Furthermore, Eskom must provide quarterly reports to NERSA on the following:

i) Coal volumes burnt per station, per contract type
ii) Coal costs per station per contract type, per station
iii) Coal quality per contract type per station.

Coal Handling

Summary of the application

6.3.79 Coal handling refers to the costs of moving coal to the boiler once delivered to the power station storage facility and coal stockyard via a dedicated mine, road and/or rail. The costs are mainly fixed and do not vary with production and/or level of coal handling.

6.3.80 The main components of coal handling costs include:

i) Labour
ii) Machinery
iii) Vehicles (Articulated Dump Truck, tripper trucks, bobcats and bulldozers)
iv) Maintenance
v) Diesel

6.3.81 Although coal-handling costs are mainly fixed, they may vary from planned values due to the following reasons:

i) Coal constraints – failure by a mine to deliver, resulting in the need to reclaim from the strategic stockpile and the additional use of yellow plant equipment and labour beyond the contracted.
ii) Contract type – stations with take or pay contracts may result in excessive coal needing to be moved to strategic piles.
iii) Conveyor spills – if conveyors spill coal, labour is required to manually load the coal onto the conveyor using shovels.

6.3.82 Type of coal transport – coal delivered via rail and/or road is generally more expensive from a coal-handling perspective because of the use of mobile equipment.

6.3.83 Weather conditions – coal from open-cast mines is exposed to weather conditions.

6.3.84 Coal-handling costs, as applied for by Eskom, are shown in **Table 59** below.

Table 59: Coal-handling cost application

Coal Handling (R'm)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Coal Handling (R'm)	2 293	2 419	3 090	3 314	3 469	3 633

NERSA Analysis

6.3.85 A historical analysis of coal-handling costs reveals a significant increase of approximately 27.7% between FY2023/24 and FY2024/25. The approved budget for coal handling in FY2024/25 was R2,507 million. This substantial variance from the allowed revenue has resulted in a distorted baseline for the application period.

Table 60: Historical coal-handling costs

Coal Handling (R'm)	Actuals FY2020	Actuals FY2021	Actuals FY2022	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Coal Handling (R'm)	2018	2234	2249	2 293	2 419	3 090	3 314	3 469	3 633
Year-on-year increase (%)		10,70	0,67	1,96	5,49	27,74	7,25	4,68	4,73

Approach/Methodology Used

6.3.86 Section 12.2.5 of the MYPD Methodology states the following regarding the treatment of coal-handling costs.

The following coal handling costs per station shall be submitted with the MYPD application: building-up stockpiles, recovering from stockpiles, maintaining stockpiles, tons moved, kilometre travelled and payment rate.

Stakeholder Comments

No stakeholder comments were received under the coal-handling section.

NERSA Adjustments and Reasons

6.3.87 An analysis of the coal-handling costs per station reveals that Camden, Duvha, Lethabo, Matla, Medupi and Tutuka are the largest contributors. These stations also experienced a year-on-year cost increase of over 20% in FY2024/25. Notably, Matla's costs are significantly inflated, showing a 207% increase in FY2024/25, with more than 50% of its expenses categorised as 'other'.

6.3.88 Given the high increase in the projected coal-handling cost in FY2024/25, which is higher than the Energy Regulator decision of R2 507m, the starting point for coal-handling cost will be set at R2 507m, and projected using the year-on-year adjustments in the application. The decision for coal-handling costs is as follows:

Table 61 : Coal handling

Coal Handling	Application			NERSA Adjustment			NERSA Decision		
	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028
Costs	3 314	3 469	3 633	-625	-655	-685	2 689	2 814	2 948

Conditions for Approval

6.3.89 Eskom must operate within the set coal-handling targets. Furthermore, Eskom must provide quarterly reports to NERSA on the following:

i) Coal-handling costs per station

Start-Up Fuel Oil and Gas

Fuel and water procurement

<u>Summary of the application</u>

6.3.90 The Primary Energy function incurs costs for decommissioning and rehabilitating mines, as well as manpower-related costs for sourcing, technical, environmental, and operational staff. These costs are not included in Generation's operating expenditure but are shown separately as Fuel Procurement Costs.

6.3.91 Eskom has applied for the fuel oil costs depicted in Table 62 below.

Table 62: Fuel and water procurement cost application

Fuel and Water Procurement Costs (R'm)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Fuel and Water Procurement Costs (R'm)	274	295	334	351	368	384

NERSA Analysis

6.3.92 The total fuel and water procurement cost increased by 7% from FY2022/23 to FY2023/24 and 12% in FY2024/25. From FY2025/26, the increase remained consistent, increasing by 4% to 5% until FY2029/30, which is within CPI.

6.3.93 Manpower costs, including recruitment, salary increases, and bonuses, contributed to the under-expenditure. Since the hiring process resumed in FY2023/24, the total expenditures increased by 12%.

6.3.94 Generation anticipates an increase in legal fees because of increased coal-related matters, which will lead to higher operating and administration costs, insurance premiums, and international database subscriptions.

Stakeholder Comments

No stakeholder comments were received under the fuel procurement section.

Approach/Methodology Used

6.3.95 The MYPD Methodology is not explicit on how fuel and water procurement should be assessed.

NERSA Adjustments and Reasons

6.3.96 NERSA will not make any adjustments on fuel and water procurement.

Table 63: Fuel and water procurement decision

Fuel and Water Procurement Costs (R'm)	Application			NERSA Adjustment			NERSA Decision		
	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028
Fuel and Water Procurement Costs (R'm)	351	368	384	0	0	0	351	368	384

Conditions for Approval

None.

Start-Up Fuel Oil and Gas

Summary of the application

6.3.97 Fuel oil plays a crucial role in stabilising combustion in coal-fired boilers, especially during transient conditions that arise from sudden load changes, equipment malfunctions, or variations in coal quality. The highest fuel oil consumption happens during a cold start-up after the plant has been offline for over 36 hours. These start-ups are needed following both planned and unplanned outages and trips.

6.3.98 Eskom has also outlined that during the MYPD5 period, there were plans to ramp down some of the stations, and the decision was reversed during the MYPD6 period, which contributed to the increase in fuel oil volumes and usage costs.

6.3.99 Eskom has applied for the fuel oil costs shown in **Table 64**.

Table 64: Fuel oil cost application

Fuel Oil Costs (R'm)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Fuel Oil Costs (R'm)	9 907	8 932	9 845	10 745	11 086	11 485

Approach/Methodology Used

6.3.100 The MYPD Methodology states that Eskom must:

Section 12.6.1.1: *determine the costs;*

Section 12.6.1.2: *demonstrate (detailed calculation) how the costs were determined; and*

Section 12.6.1.3: *provide the assumption considered when determining the costs.*

Stakeholder Concerns

6.3.101 Stakeholders are concerned about the high volumes of fuel oil applied for. They indicate that these are due to Eskom procuring poor-quality coal and, therefore, need fuel oil to support running uneconomical boilers.

Eskom Justification

6.3.102 Eskom has indicated that due to the rise in renewable non-dispatch technologies, coal plant operators often must ramp down the coal fleet to a minimum stable level (MSL). At MSL, the boilers need more support from fuel oil to support the flame.

NERSA Analysis

6.3.103 The fuel oil costs will be analysed in two parts, that is, price analysis and volume analysis.

Price analysis

6.3.104 Most Eskom power stations use Grade 3 fuel, while others use Grade 1 and Grade 2 fuel. Eskom has indicated that its projected costs vary between R12 636 and R19 455 per ton on average, depending on fuel type and the location where it is being delivered over the application period. On average, this rate is lower than the benchmark costs of R13 402 to R19 486 per ton for Grade 1, Grade 2 and Grade 3 fuel oil for the same period, as obtained from Afriforesight and Bureaux for Economic Research (BER).

Table 65: Start-up gas and fuel oil price per station (R/ton) projected by Eskom (Green < R15 000/ton and Orange > R15 000/ton)

STARTUP GAS AND FUEL OIL PRICE PER STATION (R/TON) PROJECTED BY ESKOM							
	FY2026	FY2027	FY2028	FY2029	FY2030	Average per station	Fuel Grade
Arnot	R16 094	R16 761	R17 456	R18 179	R18 932	R17 484	Grade 1
Duvha (S)	R17 811	R18 549	R19 317	R20 118	R20 952	R19 349	Grade 1
Kriel	R13 289	R13 839	R14 413	R15 010	R15 632	R14 437	Grade 1
Hendrina	R17 898	R18 640	R19 413	R20 217	R21 055	R19 445	Grade 2
Camden	R15 624	R16 272	R16 946	R17 648	R18 380	R16 974	Grade 3
Duvha (N)	R12 644	R13 188	R13 735	R14 304	R14 897	R13 754	Grage 3
Grootvlei	R11 705	R12 190	R12 695	R13 221	R13 769	R12 716	Grade 3
Kendal	R15 138	R15 766	R16 419	R17 099	R17 808	R16 446	Grade 3
Kusile	R11 631	R12 113	R12 615	R13 138	R13 682	R12 636	Grade 3
Lethabo	R15 571	R16 217	R16 889	R17 588	R18 317	R16 916	Grade 3
Majuba	R15 692	R16 343	R17 020	R17 725	R18 459	R17 048	Grade 3
Matimba	R14 693	R15 301	R15 935	R16 596	R17 283	R15 962	Grade 3
Matla	R15 573	R16 219	R16 891	R17 591	R18 319	R16 919	Grade 3
Medupi	R12 844	R13 376	R13 930	R14 507	R15 108	R13 953	Grade 3
Tutuka	R13 712	R14 281	R13 930	R14 507	R15 108	R14 308	Grade 3
Averages	R14 661	R15 270	R15 840	R16 497	R17 180	**R15 890**	

6.3.105 It is evident that Eskom is procuring fuel at an efficient rate; however, the significant price discrepancies for the same fuel grade across different power stations are concerning. This issue is particularly noticeable between Kriel and Duvha stations, which use the same fuel grade.

Table 66: NERSA fuel oil benchmark per ton

NERSA Fuel oil benchmark per ton					
	2024	**2025**	**2026**	**2027**	**2028**
Grade 1	R14 430,00	R13 530,00	R13 190,00	R12 970,00	R12 890,00
Grade 2	R19 870,00	R18 750,00	R19 030,00	R19 550,00	R20 230,00
Grade 3	R19 870,00	R18 750,00	R19 030,00	R19 550,00	R20 230,00
Annual Average	**R18 056,67**	**R17 010,00**	**R17 083,33**	**R17 356,67**	**R17 783,33**

6.3.106 Table 66 above shows the benchmark unit price of the different grades of fuel oil in rands per ton. On average, the NERSA benchmark costs are higher than the average prices that Eskom is procuring at. The graph below further illustrates the comparison between Eskom fuel oil unit price per ton vs the NERSA benchmark.

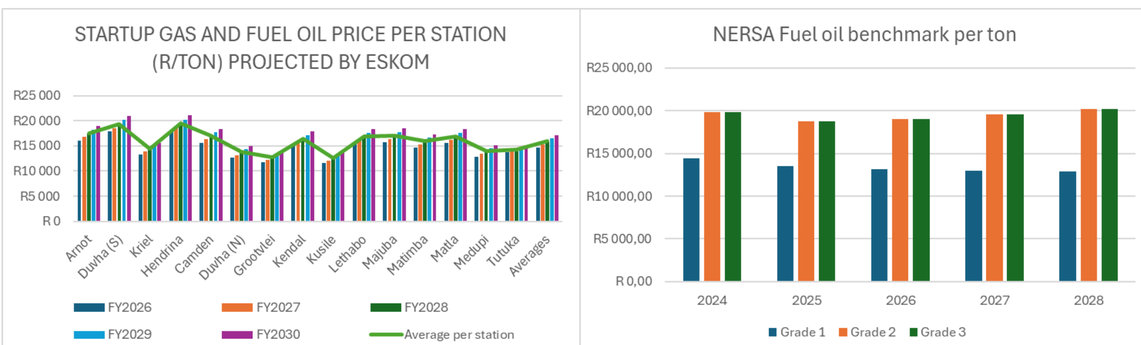

Figure 7: Comparison of Eskom fuel oil costs with benchmark

6.3.107 A review of Eskom's historical fuel oil prices reveals a troubling upward trend over the past few years. Table 67 below illustrates the historical unit cost of fuel oil, highlighting a significant increase of nearly 50% in FY2022/23. This elevated cost level is projected to persist throughout the MYPD6 period.

Table 67: Fuel oil historical costs

Years	Actual FY2020	Actual FY2021	Actual FY2022	Actual FY2023	Projection FY2024	Application FY2025	Application FY2026	Application FY2027	Application FY2028
Fuel oil unit cost/ton Application	R 7 690	R 7 540	R 8 000	R 9 000	R 8 020	R 8 250	R 14 661	R 15 270	R 15 840
Fuel oil cost/ton Actuals	R 7 540	R 6 570	R 9 930	R 14 210					

Volume analysis

6.3.108 Figure 8 below illustrates the historical trend of fuel oil volumes, comparing application volumes with actual consumption. Over the period from FY2019/20 to FY2021/22, actual consumption consistently exceeded application volumes by more than double. Application volumes are projected to remain steady at approximately 700 000 million litres annually from FY2025/26 to FY2027/28.

6.3.109 This historical pattern suggests that actual volumes are likely to surpass application volumes significantly, particularly if the underlying factors driving higher usage are not addressed. It is, however, clear that even though the fuel oil volumes have increased, the price increase is also a significant contributor to the increase in fuel oil costs applied for by Eskom.

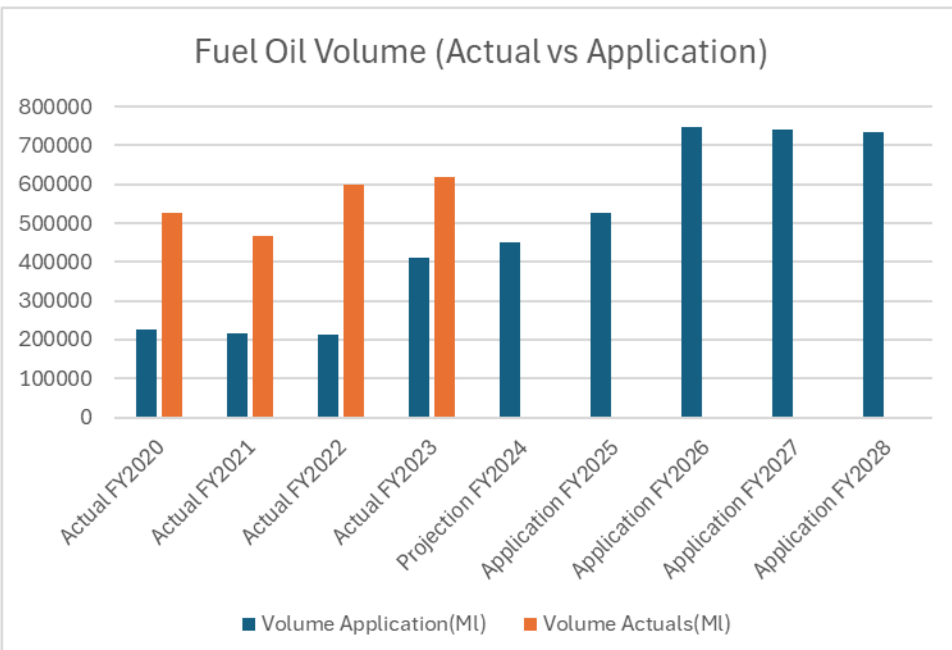

Figure 8: Historical fuel oil volumes consumed

6.3.110 One of the drivers of an increase in fuel oil usage is plant breakdowns, resulting in a need for frequent plant re-starts. From FY2024 onwards, the UCLF shows a downward trend, indicating improved plant performance. However, fuel oil usage volumes, contrary to expectations, are increasing initially, with only a slight steady decline observed after FY2025/26. As shown in Figure 9 below, fuel oil usage tends to follow UCLF.

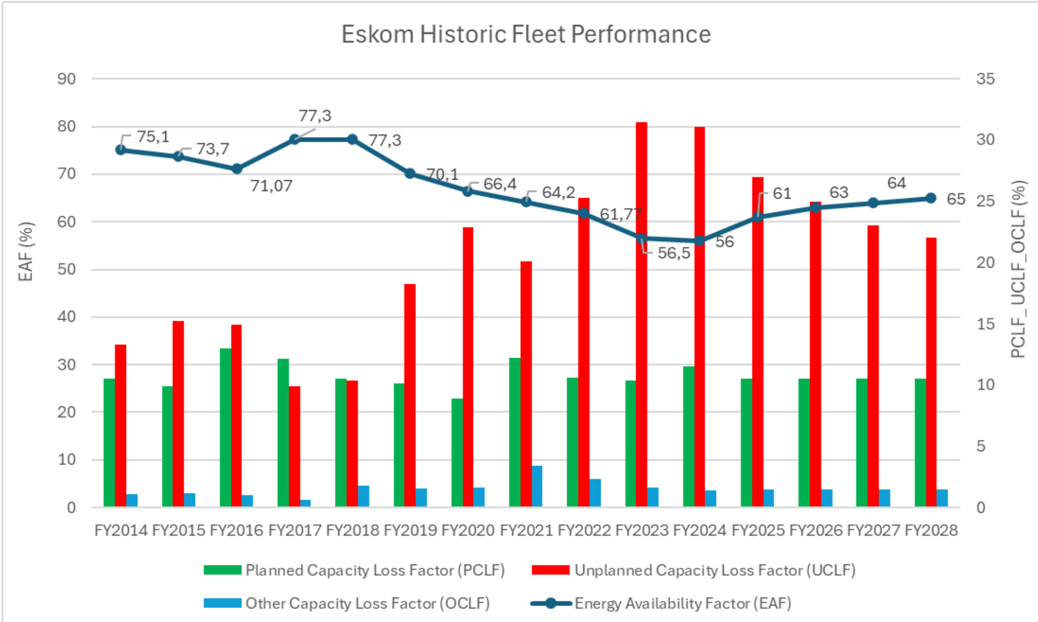

Figure 9: Eskom historical fleet performance

6.3.111 To illustrate the point of the excessively high projections for fuel oil, a comparison with historical consumption is made. The MYPD 4 consumption ranges between 468BL and 598BL, while the MYPD6 consumption ranges between 735BL and 741BL. However, the UCLF figures are similar, e.g. FY2021/22 is 25.27%, and FY2025/26 is 25%. However, there is a 149BL difference in the fuel oil usage. Eskom is, therefore, projecting much higher volumes of fuel oil for similar levels of performance.

6.3.112 Eskom has advanced that the increase in fuel oil is also due to a significant shift in the operation of the coal fleet, which needs to be operated at MSL during the day where there are high levels of energy from solar PV. Operating these plants in this manner does require additional combustion support from the fuel oil.

Stakeholder Comments

6.3.113 The City of Cape Town indicated that tariff hikes exceeding 10%, driven by primary energy costs, seem disproportionate and unjustified against only minor reductions in sales. That implications on the rationale for the magnitude of tariff increases and emphasises the need for clearer justification and cost containment.

NERSA Analysis

6.3.114 Many stakeholders believe there is a lack of transparency in the figures provided by Eskom due to discrepancies in the reported data. Concerns have also been raised about over-expenditure on fuel oil, which is seen as lacking proper accountability. Some suggest that expanding the use of independent power producers could reduce reliance on coal, thereby lowering overall expenditures. Overall, stakeholders have expressed dissatisfaction with Eskom's proposed tariff increases, citing issues of transparency, accountability, financial strain, and other concerns.

NERSA Adjustments and Reasons

6.3.115 In the production plan section, Eskom is given a performance target of an EAF of 75% for the application period, which results in a UCLF of 13% for the application period. This better performance must result in fewer automatic trips and a reduction in the fuel oil due to this has been applied.

6.3.116 Further, the improvement in performance should also make the need for flame stabilisation slightly less; therefore, a correction has also been applied for this.

6.3.117 **Table 68** below shows the fuel oil decision.

Table 68: Fuel oil decision

Fuel Oil	Application			NERSA Adjustment			NERSA Decision		
	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028
Volumes	747 620	741 366	735 450	-137 168	-136 428	-135 961	610 452	604 938	599 489
Unit Average Cost/Ton	14 373	14 953	15 617	0	0	0	14 373	14 953	15 617
Costs (R'm)	10 745	11 086	11 485	-1 971	-2 040	-2 123	8 774	9 046	9 362

Conditions for Approval

6.3.118 Eskom must operate within the set fuel oil targets. Furthermore, Eskom must provide quarterly reports to NERSA on the following:

i) Fuel oil usage per station
ii) Fuel oil cost per station
iii) Fuel oil unit costs per contract signed
iv) The additional fuel oil cost required to operate the 17 units that will be brought back to operation, will be granted on condition that the units are operational, in the course of the MYPD period.

OCGTs

Summary of the application

6.3.119 Eskom has applied for 6% capacity factor, which translates to 1 266GWh over the application years, with the cost of R10 546m, R11 029m and R11 531m, as shown in **Table 69** below.

Table 69: OCGT costs

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

6.3.120 OCGTs are the most expensive generators to be used on the system. They are considered together with the other available supply and demand options as peaking stations for use during peak hours, which provides space for essential maintenance at base-load stations as well as for emergencies as a last resort before load reductions during extreme events.

6.3.121 The diesel price is subject to the international USD price of Brent crude oil and the ZAR/USD exchange rate. The official Eskom economic parameters for the forecasting period were used in the calculation of the fuel costs. The figure below shows the diesel price used for the application. The diesel Eskom uses is subject to a wholesale discount and a fuel rebate as determined by the Minister of Finance.

Table 70: OCGT costs per station

	Fuel Prices (Rand per Litre)			
OCGT Station (Capacity)	**FY2023/24**	**Application 2025**	**Application 2026**	**Application 2027**
Gourikwa (3x148MW)	23.68	24.88	26.06	27.23
Ankerlig (3x148MW)	23.68	24.88	26.06	27.23
Acacia (1x171 MW)	12.7	13.34	13.98	14.6
Port Rex (3x57MW)	16.4	17.22	18.04	18.86

Approach/Methodology Used

6.3.122 According to the MYPD Methodology, the following should apply in terms of Sales Forecast and Production Plan.

> Section 6.1.5: *Eskom's sales volume forecast assumptions must reflect the current conditions of the market at the time of the application and should take into account the most recent actual volumes.*
>
> Section 7.1: *Eskom must furnish the Energy Regulator with the risk adjusted production plan and the energy wheel that is aligned to the forecasted sales above to be reviewed and approved by the Energy Regulator.*
>
> Section 7.3: *The Production Plan shall be adjusted accordingly when the sales volumes are adjusted to ensure alignment.*

6.3.123 The Methodology, therefore, compels Eskom to take into account all relevant information when making assumptions relating to its projected performance, and these assumptions must be adjusted for risk to ensure that the projection is as accurate as possible.

6.3.124 The OCGT will be needed to comply with sections 12.3.1, 12.3.2 and 17.2.9.4 of the MYPD4 Methodology.

6.3.125 Section 12.3.1 states, *Gas turbines are provided to operate during peak periods and emergencies. Subject to the conditions set out in the MYPD Methodology, gas turbine generation costs will be allowed as a full pass-through cost but limited to the volumes allowed by the Energy Regulator, except where such use was necessary to ensure the security of supply due to events outside management's control*.

6.3.126 Section 12.3.2 states, *Capacity constraints shall be mitigated by gas turbine generation as a last resort. For avoidance of doubt, gas turbine generation should be employed before implementation of load shedding activities*.

6.3.127 Section 17.2.9.4 states, *Usage of OCGT above the MYPD approved levels will be recovered through the RCA at the average cost of Eskom's plant that should have been available according to the production plan submitted to the Energy Regulator, if the Energy Regulator assessment* *shows that the unavailability was within Eskom management's control. For example, if coal generation availability resulted in higher than planned use of the OCGT generation, the additional OCGT energy will be recouped at the coal average cost*.

6.3.128 The OCGT will be needed to comply with section 8.1.2 of the Scheduling and Dispatch Rules – Generation Maintenance Outage Coordination.

Section 8.1.2 (a): *The short-term system integrity must be safeguarded.*
Section 8.1.2 (c): *Under constrained conditions, priority rules must be applied which take legal, commercial and safety considerations into account.*

Section 4.1 of the System Operation Code – The Operating Reserves.
Section 4.1 (a): *Operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand within ten minutes and without any energy restrictions. Operating reserves shall consist of: instantaneous reserve, regulating reserve and ten-minute reserve.*

Stakeholder Concerns

6.3.129 Eskom's operating costs are inefficient. The high use of energy-intensive OCGTs, which use expensive imported diesel, is an indication of inefficient operation. Stakeholders further indicated that OCGTs have been overused to compensate for Eskom's failing coal fleet.

6.3.130 The operating load factors of the Eskom and IPP OCGTs, and the associated diesel burn, remain significantly higher than expected for efficiently and prudently operated emergency and peaking plant, reducing the load factors of the OCGTs to levels expected for emergency and peaking plant. OCGTs should be used for their intended design purposes.

Eskom Justification

6.3.131 Eskom requests over 6% Load Factor (LF) across the application horizon. This allocation load factor considers the projected Eskom fleet performance. The assumed EAF used for the year 2025 is 63%, the year 2026 is 64%, and for the year 2027 is 65%. Should the assumptions made regarding plant performance be achieved, the OCGTs will be used at the levels applied for.

NERSA Analysis

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

6.3.133 The historically high usage of OCGTs indicates that their utilisation is directly proportional to the Unplanned Capability Factor (UCF) experienced by the power system. The same principle of proportionality applies to the usage of OCGTs in relation to the Energy Availability Factor (EAF).

6.3.134 In 2016, Eskom's usage of OCGT was an LF of 1%. This low usage was attributed to improved performance in Eskom's baseload fleet and better maintenance strategies, allowing less reliance on costly diesel-powered generation. The EAF in 2016 was 71%, and renewable energy capacity was approximately 2 205MW from projects developed under the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP). The programme comprised primarily wind, solar photovoltaic (PV) and concentrated solar power (CSP) projects. Wind energy contributed about 1 365MW, solar PV about 1 112MW, and CSP about 300MW.

6.3.135 The 1% LF means that, on average, the OCGTs were used for 15 minutes each day, and then the base load plants were able to ramp up enough to cover the peak demand.

6.3.136 Eskom's OCGT utilisation is currently at 6.3% LF, with a year-to-date EAF of 63%. This indicates that although the availability has improved, OCGTs are still required at certain periods.

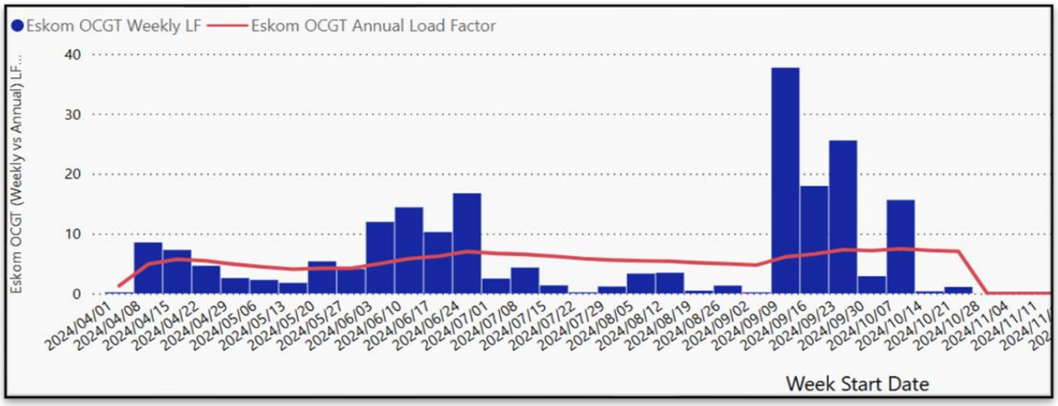

Figure 10: OCGT weekly load factor

	Week													
	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Energy Availability Factor (Eskom EAF)	65.58	65.30	67.20	70.34	69.29	64.88	66.00	67.57	65.14	66.13	59.30	60.65	58.03	62.36
Planned Outage Factor	8.35	8.35	8.26	8.53	9.07	11.27	9.98	9.19	12.55	11.68	13.50	13.16	15.45	14.04
Unplanned Outage Factor	25.65	25.85	23.96	20.37	21.35	23.36	23.66	22.89	22.01	22.01	26.57	25.85	26.17	23.29
Other Outage Factor	0.42	0.50	0.58	0.76	0.29	0.49	0.36	0.35	0.30	0.18	0.63	0.34	0.35	0.31

Figure 11: Eskom Generation plant performance for weeks 27 to 40

Stakeholder Comments

6.3.137 The Organisation Undoing Tax Abuse (OUTA) outlines that diesel overuse is due to inefficiencies in coal-fired plants, resulting in Eskom resorting to emergency plants and believes that Eskom should Implement stronger measures to reduce reliance on coal and address inefficiencies, improve governance to curb corruption, theft, and operational inefficiencies and prioritise transition to affordable and cleaner energy alternatives.

6.3.138 OUTA indicates that diesel costs also form a major part of the cost of primary energy. While significant strides have been made in reducing diesel costs in FY2024/25 to date by improving the very poor operational performance of Eskom's fleet of coal-fired power stations, the operating load factors of the Eskom and IPP OCGTs and the associated diesel burn remain significantly higher than expected for efficiently and prudently operated emergency and peaking plant.

6.3.139 It is OUTA's view that Eskom's MYPD6 revenue application does not demonstrate adequate attention and commitment to:

i. improving diesel procurement management and associated skills;
ii. exploring Eskom as a licenced diesel trader to reduce diesel import costs;
iii. enabling diesel fuel tax recovery from SARS;
iv. reducing the load factors of the OCGTs to levels expected of emergency and peaking plant;
v. using OCGTs for their intended design purposes;
vi. using BES and other short-term energy storage options to reduce OCGT load factors; and
vii. converting diesel OCGTs to gas.

NERSA Analysis

6.3.140 NERSA agrees with stakeholders that the projected unit costs of diesel procurement are higher than the benchmarked costs, and these have been adjusted accordingly. The OCGT LF has also been adjusted downwards in line with the targeted performance of 75% EAF, which has the Energy Regulator set. The role of the OCGTs, however, remains vital in providing backup to variable non-dispatchable RE technologies.

NERSA Adjustments and Reasons

6.3.141 Eskom must enhance fleet performance and achieve an Energy Availability Factor (EAF) of 75% during the application period by reducing the Unplanned Capability Loss Factor (UCLF) to 13%.

6.3.142 Taking into consideration the expected EAF performance by the Eskom fleet, combined with the fact that renewables contribute over 11 000MW to the grid, including solar and wind sources, making up a more substantial share compared to 2016. Challenges brought about by the increase in intermittency of renewables cannot be ignored.

6.3.143 A 30% availability drop of renewable during periods of low renewable generation (e.g., cloudy days or low wind), OCGTs are required to ensure grid stability during peaks. This also occurs during the evening peak after solar generation ceases, necessitating other dispatchable sources, including OCGTs, to be deployed.

6.3.144 The performance standard set by the Energy Regulator of a UCLF of 13% for FY2024/25 is similar to the year 2016. However, in 2016, the system's 30% drop in renewable energy the during peak periods equated to

661,5MW. In FY2024/25, the 30% drop in renewable energy will be 3 300MW. This would result in a load factor difference of 5% for OCGTs.

4% LF scenario

6.3.145 The 4% load factor considers the fact that an increase in renewable energy and its unavailability during peak hours will deepen the ‘duck curve’. However, with an improved EAF, the ramp rate will not require high usage of OCGTs.

6.3.146 OCGTs at 4% load factor for the duration of the application will result in OCGTs costing R7 032m for FY2024/25, R7 353m for FY2025/26 and R7 687m for FY2026/27.

3% LF scenario

6.3.147 OCGTs at 3% load factor for the duration of the application will result in OCGTs costing R5 274m for FY2024/25, R5 515m for FY2025/26 and R5 766m for FY2026/27.

Table 71: Decision for OCGTs

OCGT Usage	Decision FY 2025	Decision FY 2026	Decision FY 2027
Volume - GWh	633	633	633
OCGTs Cost-R'Mil	5274	5515	5766
Load Factor	3	3	3

6.3.148 Taking into account all the concerns raised by stakeholders regarding Eskom’s performance and the use of OCGTs at any time of the day, the 3% LF equates to an average of one hour per day of full OCGT production. While a 4% LF is a desirable target, it is not considered practical for this period. The variability of renewable energy generators must be considered. Although the NTCSA is in the process of contracting more regulating capacity, it is unlikely to achieve sufficient levels to negate the need for OCGTs.

Table 72: OCGT cost decision

OCGT Usage	Application			NERSA Adjustment			Decision		
	FY 2025	FY 2026	FY 2027	FY 2025	FY 2026	FY 2027	FY 2025	FY 2026	FY 2027
Volume - GWh	1266	1266	1266	-422	-422	-422	844	844	844
OCGTs cost-R'Mil	10548	11029	11531	-3516	-3676	-3844	7032	7353	7687
Load Factor	6	6	6	-2	-2	-2	4	4	4

Conditions for Approval

6.3.149 Eskom must submit quarterly reports to NERSA on the following:

i. System status
ii. Monthly OCGT use in terms of volumes and costs
iii. Plant performance: EAF, PCLF and UCLF per station
iv. Maintenance implemented in terms of the activities executed and costs incurred.

6.3.150 Should Eskom fail to meet the above-mentioned condition, NERSA reserves the right to review the allowed amount.

Other Primary Energy

Water usage

Summary of the application

6.3.151 Water is a critical input to power generation, particularly in conventional plants. Raw water is used for various water production processes at the station, including for direct make-up to the cooling water system, potable water and many other uses in the power station.

6.3.152 The drivers of water usage costs are as follows:

i. Water tariffs, including cost of new water infrastructure. These are legislated tariffs.
ii. Electricity (pumping costs)
iii. Amortisation and capital spend.

6.3.153 Eskom has applied for R3 936m, R3 988m and R4 359m for FY2025/26, FY2026/27 and FY2027/28, respectively. **Table 73** below illustrates the water costs that Eskom has applied for.

Table 73: Water usage costs

Water Usage Cost (R'm)	Application FY2025/26	Application FY2026/27	Application FY2027/28
Coal Stations	3 825	3 868	4 229
Koeberg	8	8	8
Peaking	100	110	120
Renewables	2	2	3
Other	1	0	0
Total	**3 936**	**3 988**	**4 359**

Approach/Methodology Used

6.3.154 Section 12.8 of the MYPD methodology state that Eskom must:

12.8.1.1*: determine the costs per station for the water to be procured and highlight the amounts of water that will be designated for each process per plant;*

12.8.1.2: *demonstrate (detailed calculation) how the costs were determined; and*

12.8.1.3: *provide the assumption considered when determining the costs.*

Stakeholder Concerns

6.3.155 There were no specific concerns raised by stakeholders on the water usage costs.

NERSA Analysis

6.3.156 Historically, the water cost has been low as a percentage of the Eskom operating cost. This is attributed to the fact that the water infrastructure is old and has completely depreciated. However, the cost of water has increased due to the introduction of new infrastructure.

6.3.157 The risk of these projections is that 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, which will be reflected in the revised National Water Pricing Strategy. Eskom is, therefore, a price taker in terms of the cost of raw water.

6.3.158 The volumes of water consumed are primarily driven by the electricity produced by power stations. The volume consumed to generate a unit of electricity varies per power station. Stations that use dry cooling systems consume less water than those using conventional cooling towers.

6.3.159 The total consumption will depend on the mix of stations used to generate electricity, with older stations consuming more. Since most of Eskom's stations are beyond the halfway mark of their lifespans, they tend to consume more water.

6.3.160 Although the coal-fired stations produced less energy than was assumed over the MYPD5 horizon, actual water consumption per unit of electricity was higher at most stations than was assumed, resulting in a total increase in water used.

6.3.161 The price of water is impacted by the tariffs that the government gazettes and the volumes consumed. Eskom assumed water-related costs would increase by an average of 9% over the application period.

6.3.162 The power stations with the highest water usage costs include Matla, Kriel and Duvha. However, regarding the volume of water used, the highest water consumption is at Matla, Lethabo and Kriel coal-fired power stations.

6.3.163 The litres per kilowatt hour consumed will be set according to the forecasted performance. At 3.43 l/kWh, Tutuka utilises more water to produce one kilowatt hour of electricity, Kriel consumes 2.74 l/kWh, and Grootvlei is at 3.11 l/kWh for the MYPD6 period.

6.3.164 The three wet-cooled power stations in terms of litres per kilowatt hour are in line with the NTPC and Power Grid Corporation of India Limited (PGCIL) 2023 benchmark that ranges between 2.5 and 3.5 l/kWh.

Stakeholder Comments and Analysis

6.3.165 No stakeholder comments were received on the water usage section.

NERSA Adjustments and Reasons

6.3.166 Based on the graph below, according to MYPD5, Eskom consumed more water than forecasted. This can be attributed to factors such as leaks within the power station's water infrastructure system.

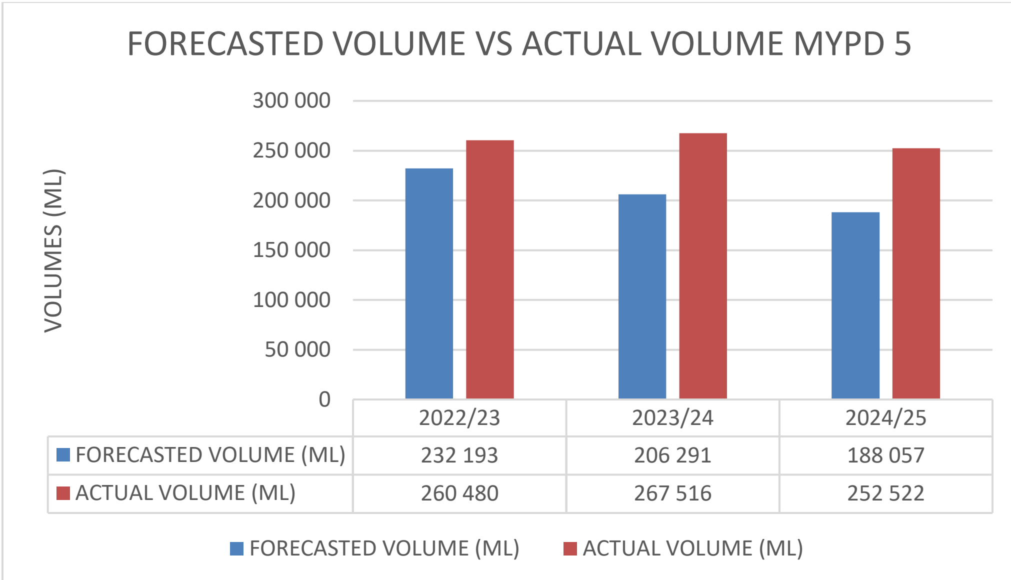

Figure 12: Forecasted vs actual water volumes

6.3.167 The graph below indicates the decrease in the l/kWh from MYPD5 to MYPD6 from 1.38 to 1.20 l/kWh. This decline in the rate of water usage in the generation process is welcomed as it points to improvements in the water leakages within the system.

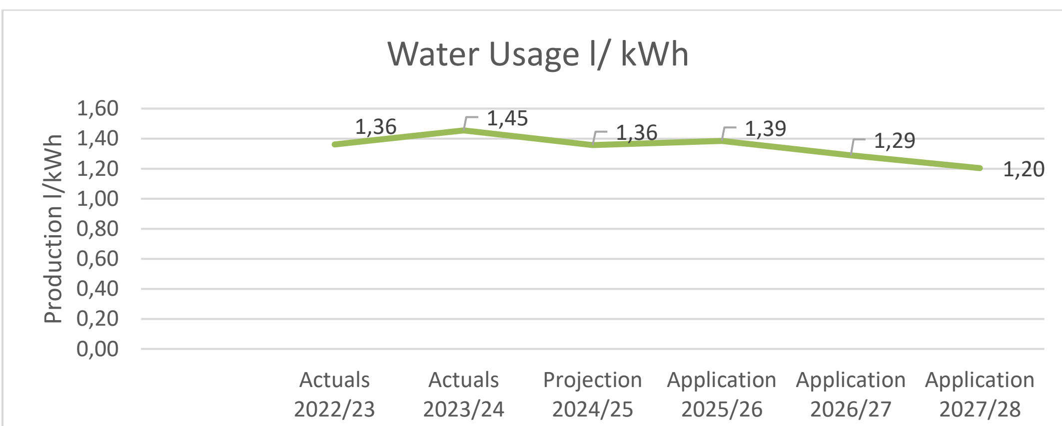

Figure 13: Water usage in L/kWh

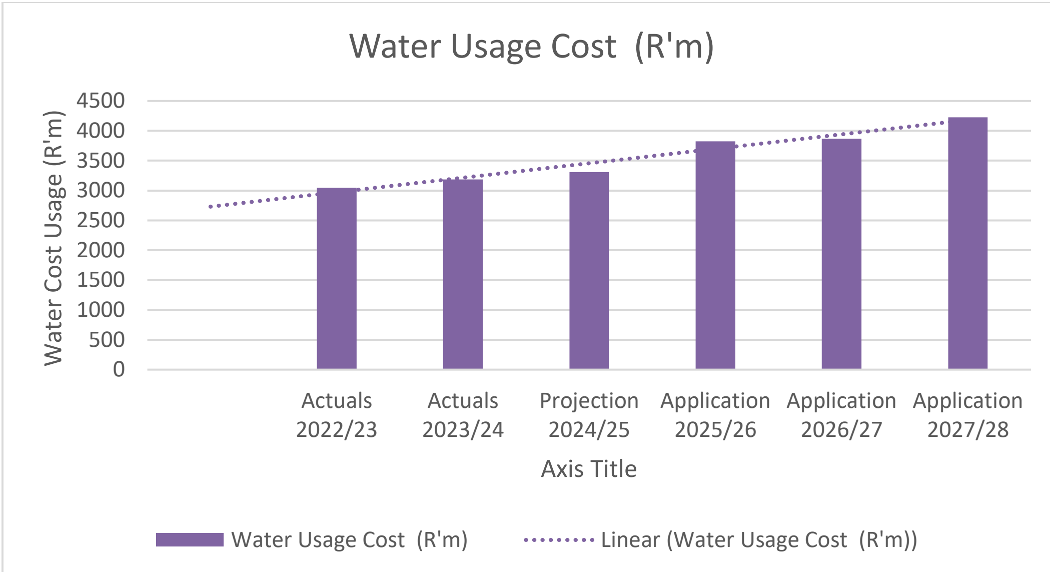

Figure 14: Water usage costs

6.3.168 The graph above illustrates the water usage cost from MYPD5 to MYPD6. It is noted that the average increase is at 6.8%, which is above inflation. Table 75 below highlights the historical unit cost of raw water. This trend indicates that the driver of the increase in water costs is not the volumes, as these have been declining, but rather the cost of procuring the raw water, which is projected to have double-digit increases.

Table 74: Historical water usage costs and rate of increases year-on-year

Water Volume (ML)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Water Volume (ML)	260 480	267 516	252 522	245 605	219 231	175 467
Water Costs (R'mil)	2 332	2 573	3 368	3 936	3 988	4 359
Unit Cost (R/L)	0,0090	0,0096	0,0133	0,0160	0,0182	0,0248
Rate of increase		7	39	20	14	37

6.3.169 Given that Eskom is a price taker in terms of water procurement, it is recommended that no adjustment be made to the costs applied for by Eskom.

6.3.170 The changes in the production plan for the additional production from coal result in an increase in water usage costs, as shown in **Table 75** below.

Table 75: Water usage cost decision

Water Usage	Application			NERSA Adjustment			NERSA Decision		
	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028
Costs	3 936	3 988	4 359	225	322	1 060	4 161	4 310	5 419

Conditions of Approval

6.3.171 The revenue is granted on condition that the volumes of water utilised are reduced in line with the efficient use of water as approved by NERSA. This can be achieved through fixing leaks and ensuring that power stations that use more water than is efficient, utilise the efficient levels of water.

6.3.172 Eskom must report on water usage per power station on a quarterly basis.

6.3.173 The over-utilisation of water will not be allowed through the RCA.

Water Treatment Costs

Summary of the application

6.3.174 Raw water is treated through the following processes:

i. Demineralised water production
ii. Potable water production
iii. Condensate polishing
iv. Cooling water treatment
v. Ash water treatment
vi. Sewage water treatment

6.3.175 Eskom has applied for R1 014m, R986 and R1 029 for FY2025/26, FY2026/27 and FY2027/28, respectively. **Table 76** below summarises the water treatment costs as applied for by Eskom.

Table 76: Water treatment costs

Water Treatment Cost (R'm)	Application FY2026	Application FY2027	Application FY2028
Water Treatment Cost (R'm)	1 014	986	1 029

Approach/Methodology Used

6.3.176 Section 12.9 of the MYPD Methodology states that:

12.9.1: *Eskom must determine the costs per station, particularly the cost of chemicals, electricity usage and labour.*
12.9.2: *Eskom must demonstrate (in a detailed calculation per station, highlighting the costs mentioned above) how the costs were determined.*

12.9.3: *Eskom must provide the assumption considered when determining the costs per station*.

Stakeholder Concerns

6.3.177 There were no concerns highlighted by stakeholders on the water treatment costs specifically.

Eskom’s Justification

None.

NERSA Analysis

6.3.178 In the pretreatment process, various chemicals are used, including coagulants, flocculants and disinfectants, which are the main costs of this process.

6.3.179 The main driver of water treatment cost is the cost of the chemicals used to treat the raw water. Therefore, the quality of raw water will also determine how much chemicals will be utilised.

Stakeholder Comments

No stakeholder comments were received on the water treatment section.

NERSA Adjustments and Reasons

6.3.180 The basis of the analysis focuses on the past MYPD application periods and RCA applications. Analysis of MYPD4, MYPD5 and MYPD6 applications of water treatment costs reveals that the average percentage increase in the cost of water treatment is 10%. The graph below shows the historical data.

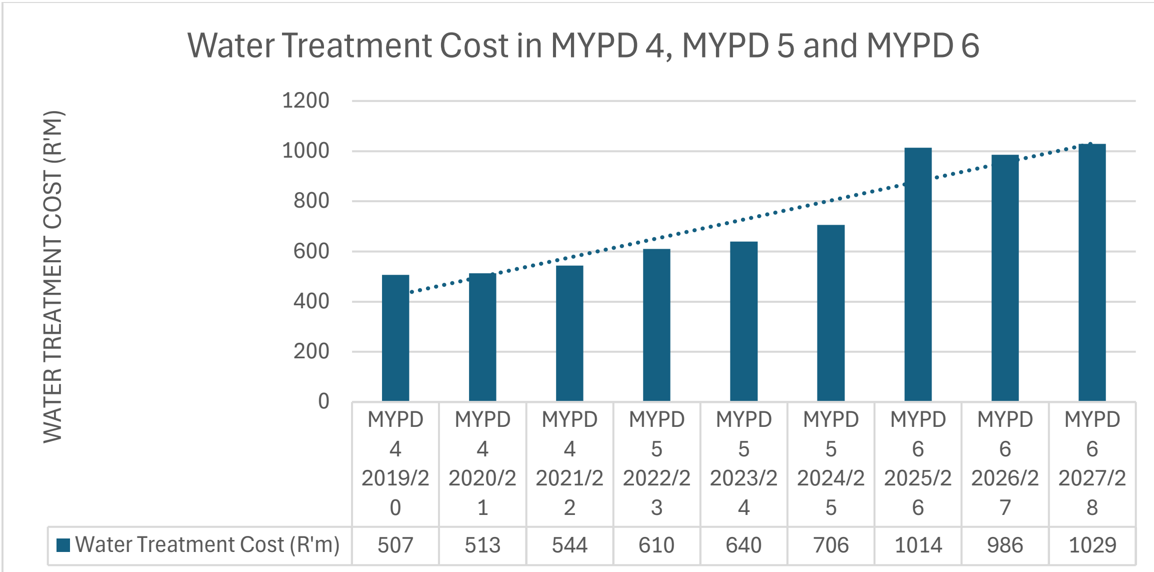

Figure 15: Historical water treatment costs

6.3.181 The table below shows the year-on-year increase in water treatment costs, highlighting very high increases over the MYPD5 period, while the increases over the MYPD6 period are low. Worrying is the 27% increase in FY2023/24, which results in the starting point of FY2025/26 being fairly high.

Table 77: Water treatment year-on-year increases

Water Treatment Costs (R'm)	MYPD4 FT2020	MYPD4 FT2021	MYPD4 FT2022	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Water Treatment Costs (R'm)	484	660	616	669	848	1 004	1 014	986	1 029
Year-on-Year increase (%)		36	-7	9	27	18	1	-3	4

6.3.182 The costs are, therefore, adjusted to reflect the Energy Regulator decision for FY2024/25 and increased by CPI for the duration of the application. This results in the decision below.

Table 78: Water treatment cost decision

Water Treatment	Application			NERSA Adjustment			NERSA Decision		
	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028
Costs	1 014	986	1 029	-316	-257	-268	698	729	761

Conditions of Approval

6.3.183 The allowable revenue (AR) is granted on the following conditions:

i) That Eskom remains within the efficient water treatment costs.

ii) Inefficient water treatment costs should be reduced in line with the efficient water treatment costs approved by NERSA. Eskom must report on water treatment costs per power station quarterly.

iii) Inefficient water treatment costs will not be allowed through the RCA.

Sorbent Usage and Handling

Summary of the application

6.3.184 Eskom has applied for sorbent costs, including transport for R459m, R482m and R454m for FY2025/26, FY2026/27 and FY2027/28, respectively. In addition, Eskom has applied for sorbent handling for R23m, R24m and R20m for FY2025/26, FY2026/27 and FY2027/28, respectively. Table 79**: Sorbent** below summarises the sorbent cost and handling.

Table 79: Sorbent costs

Sorbent Usage	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028
Volume (kt)	201	71	380	457	453	404
Costs (R'm)	186	366	361	455	477	449
Sorbent Handling Costs (R'm)	6	17	23	23	24	20

6.3.185 Sorbent is required for the flue gas desulphurisation (FGD) technology at Medupi and Kusile power stations. The sources identified for limestone are in the Northern Cape. The limestone is transported by rail from the Northern Cape to Gauteng. The remote location of lime significantly increases the delivery cost.

Approach/Methodology Used

6.3.186 Section 12.6 of the MYPD methodology states that:

12.6.1 *Eskom must:*

12.6.1.1 *determine the costs;*

12.6.1.2 *demonstrate (detailed calculation) how the costs were determined; and*

12.6.1.3 *provide the assumption considered when determining the costs.*

Stakeholder Concerns

6.3.187 There were no specific concerns highlighted by stakeholder on the water treatment costs.

Eskom's Justification

None.

NERSA Analysis

6.3.188 The lack of rail infrastructure means that sorbents must be trucked to the power stations. This significantly increases the delivery costs of sorbents.

6.3.189 These projections exclude the Medupi Power Station because it will be retrofitted with FGD at a later stage. Therefore, this application is applicable to the Kusile Power Station.

6.3.190 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 PPI.

Stakeholder Comments

6.3.191 No stakeholder comments were received on the sorbent usage section.

NERSA Adjustments and Reasons

6.3.192 The volume of the sorbents to be used for this application period is 28% higher than the volume utilised in MYPD5 due to the additional Kusile units that have gone online. The forecasted production of the Kusile Power Station for the MPYD6 application is 18%, which is higher than the forecasted production of MYPD5. **Table 80** below provides an average increase in sorbent usage costs and sorbent handling.

Table 80: Historical sorbent costs

Sorbent Historical Analysis	MYPD 5 FY2023	MYPD 5 FY2024	MYPD 5 FY2025	MYPD 6 FY2026	MYPD 6 FY2027	MYPD 6 FY 2028
Sorbent Usage Cost (R'm)	261	355	490	455	477	449
% Increase		36,02	38,03	-7,14	4,84	-5,87

6.3.193 It is observed that the average increase percentage of the MYPD6 is lower than the MYPD5 period and lower than inflation.

6.3.194 This cost modelling is based on the cost assumptions that the sorbent cost is R182/ton (base year 2026) and the cost for transport, which includes rail and road elements, is at R822/ton. The benchmark used to compare the sorbent cost pegged the cost of limestone at R171/ton in July 2024; projected costs could not be obtained; the R182/ton value is therefore found to be reasonable for the MYPD6 application period.

Table 81: Historical sorbent consumption rate

	MYPD 5 FY2023	MYPD 5 FY2024	MYPD 5 FY2025	MYPD 6 FY2026	MYPD 6 FY2027	MYPD 6 FY 2028
Volume (kt)	201	71	380	457	453	404
Forecasted Generation (GWh)	9 119	9 525	15 956	19 198	19 041	16 988

Consumption kt/GWh	0.022	0.0074	0.024	0.024	0.024	0.024

6.3.195 According to the table above, the sorbent consumption of 0.024 kt/GWh has been kept constant throughout the MYPD6 application projection. It does not significantly differ from the MYPD5 FY2022/23 and FY2024/25. This alludes to efficiency in terms of the sorbent usage cost.

6.3.196 Sorbents handling of the MPYD6 application are much lower than the percentage increase of the MYPD5 application, which was at 6%. Therefore, it is recommended that no adjustment be made on the application.

6.3.197 The sorbent consumption for the MYPD6 application period is below the 2023 NTPC and Power Grid Corporation of India Limited (PGCIL) benchmark, which ranges between 0.1 and 0.2 kt/GWh. The sorbent utilisation is, therefore, satisfactory.

6.3.198 The changes in the production plan for the additional production from coal result in an increase in sorbent usage costs, as shown below.

Table 82: Sorbent costs

Sorbent (R'mil)	Application			NERSA Adjustment			NERSA Decision		
	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028	FY2026	FY2027	FY2028
Sorbent Usage Costs	459	482	454	26,18	38,96	110,44	485,18	520,96	564,44
Sorbent Handling Costs	23	24	20	0	0	0	23	24	20

Table 83: Nuclear

Nuclear fuel Income Statement Cost R'm	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Nuclear fuel burn (Units 1+2) *	513	497	632	848	1 396	1 496	1 758	1 906
Fuel written off	17	19	77	34	30	71	98	237
Depreciation of decomm asset	109	120	117	86	60	67	80	72
Nuclear Other	36	14	14	14	33	14	15	16
Total nuclear fuel burn costs	675	649	840	982	1 519	1 648	1 951	2 231
Nuclear power station, GWh (net)	9 803	8 131	9 001	10 965	14 359	12 973	14 056	14 599
Generation Cost c/kWh	6.89	7.98	9.33	8.96	10.58	12.70	13.88	15.28

6.3.199 Eskom made the following application for its nuclear primary energy cost.

6.3.200 Eskom's application was evaluated according to section 12.4 of the Methodology, which states:

12.4.1 Eskom must:

12.4.1.1 determine the nuclear operation costs.

12.4.1.2 demonstrate (detailed calculation) how the costs were determined; and

12.4.1.3 provide the assumption considered when determining the costs.

6.3.201 Eskom has met the necessary requirements in its application, and its figures are reasonable. Consequently, no adjustments have been made.

Table 84: Primary energy nuclear decision

Nuclear fuel Cost R'm	Application FY2026	Adjustment	NERSA Decision FY2026	Application FY2027	Adjustment	NERSA Decision FY2027	Application FY2028	Adjustment	NERSA Decision FY2028
Nuclear fuel burn (Units 1+2) *	848	0	848	1 396	0	1 396	1 496	0	1 496
Fuel written off	34	0	34	30	0	30	71	0	71
Depreciation of decomm asset	86	0	86	60	0	60	67	0	67
Nuclear Other	14	0	14	33	0	33	14	0	14
Total nuclear fuel burn costs	**982**	**0**	**982**	**1 519**	**0**	**1 519**	**1 648**	**0**	**1 648**

6.4 Environmental Levies

Summary of the application

6.4.1 Eskom Generation is applying for the total costs of R6 539m, R6 279m and R5 337m to be recovered as environmental levy for the MYPD6 2025/26 (Y1), 2026/27 (Y2) and 2027/28 (Y3), respectively, as shown in **Table 85** below.

Table 85: Environmental levy

ENVIRONMENTAL LEVY	Application FY2025/26	Application FY2026/27	Application FY2027/28
Total Non-Renewable Energy sent out (GWh)	171 935	165 181	140 480
Add: Auxiliary volumes (GWh)	14 904	14 216	12 004
Generating Volumes	**186 839**	**179 397**	**152 484**
Rate in kWh	3,5	3,5	3,5
Generation Levy Cost	**6 539**	**6 279**	**5 337**

NERSA Analysis

6.4.2 Levies and taxes are any charges imposed by the Government and are payable by Eskom. Government Gazette No. 32309, dated 1 July 2012, set the rate at 3.5c/kWh, which are actual payments to SARS and are determined by the true metered generated volumes.

6.4.3 In this application, Eskom indicated that the Generation Production Plan that measures Energy Sent Out (ESO) as measured after the high voltage transformer was used to derive the assumed cost. This derived generated volume is then charged at the applicable Environmental Levy rate for that period to obtain the forecast cost per power station. It is assumed that no further rate increases will occur during the planning period.

6.4.4 These costs are calculated by considering various components, including coal costs, gas turbine generation and nuclear costs, excluding clean energy sources such as hydro stations, pump storage and wind energy. Furthermore, levies must also be fully aligned with the officially approved Generation sales volumes. The Generation Production Plan is the only source that could be used as a prudent source of the volume applicable that is liable for the payment of the environmental levy.

6.4.5 NERSA does not have a mandate on the levies, as these are policy issues enacted by the government.

Approach/Methodology Used

6.4.6 Section 16.4.1 of the MYPD4 Methodology states, 'Taxes and levies will be treated as a pass-through cost in the MYPD'. Section 16.4.2 indicates that taxes and levies 'will be treated as a separate account in the Eskom revenue determination'.

6.4.7 According to the Methodology, 'Any over or under-recovery will be recorded in the RCA'.

NERSA Adjustments and Reasons

6.4.8 **Table 86** below shows NERSA's decision based on the changes made by NERSA under the production plan section. The amount of GWh to be produced from non-renewables for the 2025/26, 2026/27 and 2027/28 financial years has changed due to the changes in the production plan, that is, the increase in sales projection, reduction of the OCGT LF to 4% over the application period, as well as the reduction in REIPPPP contribution over the application period, requiring an increase in energy sent out from coal generation.

6.4.9 This implies that the total environmental levy to be paid for the entire MYPD6 control period will also change. The revised environmental levy allowed is R6 790m for FY2025/26, R6 617m for FY2026/27 and R6 218m for FY2027/28, respectively.

Table 86: NERSA decision on environmental levy

	FY 2025/26			FY 2026/27			FY 2027/28		
Environmental Levy	Application	Adjustments	NERSA Decision	Application	Adjustments	NERSA Decision	Application	Adjustments	NERSA Decision
Total Non Renewable Energy Sent Out (GWh) [a]	171 935	7 169	179 104	165 181	9 651	174 832	140 480	25 169	165 649
Add: Auxilliary volumes (GWh) [b] = [a] x Specific Station Aux%	14 904	0	14 904	14 216	0	14 216	12 004	0	12 004
Generating volumes [c] = [a + b]	**186 839**	**7 169**	**194 008**	**179 397**	**9 651**	**189 048**	**152 484**	**25 169**	**177 653**
Rate in c/kWh [d]	3,5		3,5	3,5		3,5	3,5		3,5
Generation Levy cost (Rm) [e] = [c] x [d]	**6 539**	**251**	**6 790**	**6 279**	**338**	**6 617**	**5 337**	**881**	**6 218**

Conditions for Approval

6.4.10 There are no conditions of approval as the levies are policy issues enacted by the government.

Stakeholder Comments

6.4.11 During public hearings, stakeholders raised concerns about customers bearing environmental levy costs. As this is a policy decision, the team requested a meeting with the National Treasury to discuss the matter. During a meeting held on 20 and 21 January 2025, the National Treasury advised that in its 2024 Phase 2 Carbon Tax Discussion Paper, it proposed to remove the electricity generation levy and apply the carbon tax on electricity generation from 2026. This would be a shift from one tax to another and would not impact electricity prices.

6.5 Carbon Tax

Summary of the application

6.5.1 The Carbon Tax Act, 2019 (Act No. 15 of 2019) came into effect on 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 [CO2eq]), and matters connected therewith.

Table 87: Carbon tax application

Carbon dioxide emissions*	Projection		Application			Post Application	
	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Acacia	1	0	0	0	0	0	0
Ankerlig**	1 086	653	652	652	652	652	652
Gourikwa**	1 031	411	411	411	411	411	411
Port Rex	2	0	0	0	0	0	0
Kusile	8 336	12 997	19 198	19 041	16 988	14 574	16 143
Medupi	20 914	21 242	18 347	16 328	15 753	14 053	14 245
Duvha	14 023	9 801	10 106	9 181	6 890	5 838	3 376
Kendal	12 204	18 606	16 729	18 452	15 297	14 420	14 371
Lethabo	23 803	21 317	17 417	16 910	14 016	13 965	14 120
Majuba	22 064	17 644	16 652	18 411	12 305	11 319	10 861
Matimba	19 404	21 682	16 506	16 262	16 431	14 328	14 340
Matla	16 096	16 860	16 099	14 324	13 927	11 098	9 841
Tutuka	8 614	9 062	11 502	8 679	4 759	3 175	3 225
Arnot	11 869	9 528	10 610	9 218	8 127	6 482	6 093
Camden	10 830	7 917	6 867	6 163	1 945	1 708	1 688
Grootvlei	2 916	3 720	2803	1 387	1 350	1 413	1 525
Hendrina	4 229	5 173	5 586	2 856	1 658	1 607	1 691
Komati	-	-	0	0	0	0	0
Kriel 1_3 (UG)	4 958	7 127	4 603	5 345	4 686	4 403	4 242
Kriel 4_6 (OC)	5 902	4 940	6 662	4 957	5 383	3 682	5 047
Kusile Pre-Comm	1 411	2958	-	-	-	0	0
Medupi Pre-Comm	-	-	0	0	0	0	0
Virtual Station (coal fired average 1.2 tonnes CO_2/MWh)	0	0	0	0	0	0	0
Total qualifying carbon dioxide (CO_2) emissions (kilotonnes) [a]	187 573	190 575	179 687	167 515	139 516	122 065	120 807
Multiply: tax-free allowances*** (60% for category 1A1a) [b] = [a] x 0.6	112 544	114 345	107 812	100 509	83 710	73 239	72 484
Net emission equivalent [c] = [a] - [b]	**75 029**	**76 230**	**71 875**	**67 006**	**55 806**	**48 826**	**48 323**
Carbon tax rate in R/tonneCO_2eq [d]*****	159	190	236	308	347	385	424
Carbon tax rate in R/tonneCO_2eq [e]*****	190	236	308	347	385	424	462
Gross carbon tax levy liability (Rm) [f] = [[0.75 x [c] x [d]] + [0.25 x [c] x [e]]]/1000	**12511**	**15360**	**18256**	**21291**	**19895**	**19274**	**20948**
Additional deductions to "generators of electricity from fossil-fuels" [g]	Environmental levy paid; Renewable premium calculated on REIPPPP volumes		0 from 1 January 2025 (last 3 months of the FY)	0			
Net carbon tax levy liability after deductions (Rm) [h] = [f] - [g]	**0**	**0**	**5 534**	**21 291**	**19 895**	**19 274**	**20 948**

NERSA Analysis

6.5.2 The National Treasury introduced an additional tax that impacts the electricity price. The Carbon Tax Act of 2019 provides for the imposition of a tax on the greenhouse gas emissions of a company (expressed in carbon dioxide equivalents [CO2eq]), and matters connected therewith.

6.5.3 The tax rate was introduced at R120/tonne CO2eq, but the Carbon Tax Act specifies that the tax must escalate at CPI+2% during phase 1 of the tax (i.e. for 2020, 2021 and 2022) and then at CPI thereafter.

6.5.4 The Methodology provides for all taxes and levies through costs; therefore, carbon taxes will be dealt with as such.

Verification

6.5.5 The team requested a meeting with the National Treasury to discuss the matter. During the meeting held on 20 and 21 January 2025, the National Treasury advised as follows:

6.5.5.1 Phase 2 Carbon Tax Discussion Paper was published for public comment and consultation in November 2024. The paper contains proposals for the 2nd phase of the carbon tax, including proposals to extend the commitment to electricity price neutrality, i.e. **No impact on electricity prices due to the carbon tax until 2030.**

6.5.5.2 To protect households and energy-intensive companies from potential adverse impacts of higher energy prices, electricity generators can offset the electricity generation levy and renewable energy premium against the carbon tax liability. **In 2022, the electricity price neutrality commitment was extended to December 2025** to allow for the economic recovery after the COVID pandemic. It was also proposed that the electricity price neutrality commitment be extended for a further three to five years to facilitate a just transition.

6.5.5.3 In the 2024 Phase 2 Carbon Tax Discussion Paper, it is **proposed to remove the electricity generation levy and apply the carbon tax on electricity generation from 2026. This would be a shift from one tax to another and would not impact electricity prices**. The renewable energy premium credit can be utilised by electricity generators to reduce their carbon tax liability to zero. **The proposals will ensure that there is no additional impact on electricity prices due to the carbon tax until 2030.**

6.5.6 Section 16.4 of the MYPD Methodology states:

16.4.1 The taxes and levies will be treated as a pass-through cost in the MYPD.

16.4.2 Taxes and levies will be treated as a separate account in the Eskom revenue determination.

16.4.3 Eskom must ensure that tax and levy costs are specified and that the calculation thereof is clear and concise.

16.4.4 The amount provided for the taxes and levies must be ring-fenced and any over or under-recovery will be recorded in the RCA.

NERSA Adjustments and Reasons

6.5.7 The National Treasury has indicated that the environmental levy will be removed, and the carbon tax will be applicable from 2026. This would be a shift from one tax to another and would not impact electricity prices until 2030.

Recommendation

6.5.8 It is recommended that the carbon tax cost be disallowed as it is similar to the environmental levy. These serve the same purpose of discouraging generators from using dirty fuel and encouraging them to use clean energy.

Conditions for Approval

6.5.9 Changes in legislation will be considered as and when required.

7. CONFIDENTIALITY

7.1 All figures are confidential until the RfD has been approved for publication.

8. CONCLUSION AND RECOMMENDATION

8.1 From the conspectus of the facts and evidence presented to the Energy Regulator, it is appropriate to consider the review of Eskom's Revenue applications.

End.