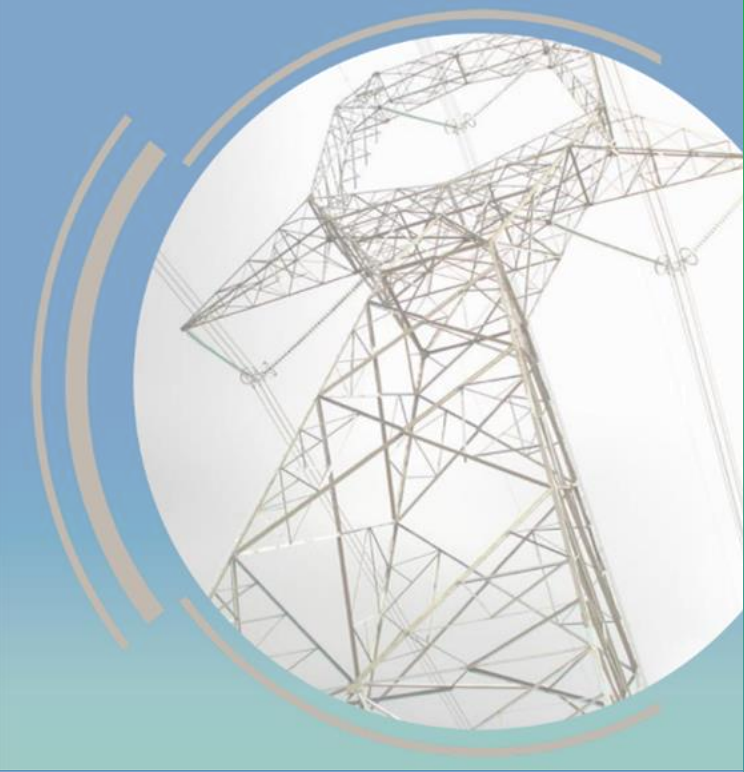

Regulatory Clearing Account (RCA)

MYPD 5 FY2023

Submission to NERSA

24 January 2024

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1 Preface

This document summarises information submitted by Eskom Holdings (SOC) Ltd to the National Energy Regulator of South Africa (NERSA) pertaining to Eskom's Regulatory Clearing Account (RCA) balance for FY2023 in accordance with the Multi-Year Price Determination Methodology published during October 2016.

1.1 The basis of submission

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

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

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

2 Executive Summary

2.1 Context of the NERSA FY2023 revenue decision

The revenue application for FY2023 was prepared in accordance with MYPD methodology as published by NERSA during October 2016. The Energy Regulator's allowable revenue decision for FY2023 was R264 864m for all customers (inclusive of previous RCA liquidations) with an average nominal price increase of 9.61% for standard tariff customers. FY2023 is the first year of the MYPD5 period. The NERSA revenue decision was announced on 24 February 2022. The reasons for decision were published on 23 June 2023.

2.2 Summary of FY2023 RCA application

The overall RCA variance being applied for is R9m for the benefit of Eskom. The FY2023 RCA submission is driven substantially by the revenue variance and certain cost variances. These cost variances are either for the benefit of Eskom or consumers. The revenue variance, after adjustments results in the variance being for the benefit of the consumer. The key adjustment is related to ensuring that consumers are not burdened with revenue not recovered due to load shedding. This has been the tradition for each of the previous years. This by no means that Eskom's performance is the only reason for load shedding. The details will be demonstrated in the production plan section. The key cost variances were in primary energy, depreciation, international purchases and carbon tax. The introduction of carbon tax was delayed and not introduced as assumed by NERSA in its decision. NERSA did not make any service quality incentive decisions for the MYPD 5 period. Variances in Eskom and IPP OCGT costs were in relation to minimising loadshedding due to capacity constraints.

Table 1: Summary of FY2023 RCA Application

RCA for FY2023	Decision FY2023	Actuals FY2023	Variance	RCA Adjustments	RCA FY2023
Regulated Assets Base (RAB)	702 931	769 067	66 136	-	
Return on Assets (ROA)	1.08%	1.08%			-
Return	7 557	8 268	711	-	711
Expenditure	62 513	78 448	15 935	(15 742)	193
Primary Energy	80 496	100 040	19 544	12	19 556
Independent Power Producers (local)	43 130	43 534	404	-	404
International purchases	4 589	6 459	1 870	-	1 870
Depreciation	42 321	45 151	2 830	-	2 830
Levies & taxes	7 132	7 033	(99)	-	(99)
Carbon Tax	2 714	-	(2 714)	-	(2 714)
Revenue	250 452	259 541	(9 090)	(13 734)	(22 824)
SQI	-	-	-	-	-
FY2023 RCA Balance due to Eskom					**(74)**
Nuclear decommissioning from RCA 2013/14 decision liquidated over 10 years - (10th year of 10 years)					83
Total RCA balance (R'm)					**9**

Note:
a) The *costs variance* is calculated as *Actual* minus *Decision*
b) *Revenue variance* is calculated as *Decision* minus *Actual*

NB: The RCA adjustments address mainly the following:

- Revenue - adjustments are made to revenue reflected in the annual financial statements that ensures that all billed revenue is included, non-electricity revenue is not included, and the correct allocation of demand response revenue. Adjustments are also made in respect to the revenue related to pre-commissioning energy. This in in accordance with the NERSA decision in the FY2019 RCA. Revenue and costs relating to pre-commissioned units that are capitalised under IFRS are included in the income statement for regulatory purposes and the net effect is thus included in the revenue variance.
- Revenue related to the reduction is sales volumes due to loadshedding is also addressed. The adjustment is to the benefit of the consumer. This has always been the practice related to revenue related to sales volume variance due to load shedding.
- Primary energy adjustments from financial results are due mainly to the application of NERSA's MYPD methodology for coal costs.
- Operating Costs – adjustments are mainly because of other income and arrear debt.

2.3 Basis of RCA Application

The adherence to relevant legislative, regulatory and license requirements, court judgements and orders form the basis of the RCA submission. These include the Electricity Pricing Policy, Electricity Regulation Act, MYPD methodology, South African Grid and Distribution Codes and guideline on prudency assessment. Eskom has also based this application on precedents set in the MYPD2 RCA and the FY2014 RCA decisions. Certain changes made by NERSA in the subsequent RCA decisions were not considered. Eskom has successfully reviewed the RCA decisions for the 2015, 2016 and 2017 financial years. The outcome of the Judgement related to this case is also used as the basis of this RCA application. NERSA made a remittal decision on the three RCAs. However, this decision is being re-reviewed due to Eskom's submission that the Court order and judgement were not considered in this remitted decision. For similar reasons, Eskom has also reviewed the NERSA FY2018, FY2019, FY2020 and FY2021 RCA decisions.

2.4 Revenue variance

The MYPD methodology requires the recovery of the total variance in revenue where certain adjustments are made to the revenue reflected in Eskom's annual financial statements. A revenue variance of R22 824m for the benefit of the consumer, is included in the RCA balance. This is due mainly to any loadshedding sales volume not being included in the RCA balance. Adjustments include ensuring all billed revenue is considered, revenue from non-electricity sources is excluded and loadshedding revenue variances are specifically excluded. The load shed energy, implemented in accordance with NERSA requirements, is estimated at 13 477GWh where the total corresponding revenue is excluded from the variance. Adjustments for the revenue related to pre-commissioning energy is also made.

The MYPD methodology requires the adjustment of the **total** revenue variance. This approach allows for recovery of fixed cost. The methodology allows for adjustment of variable costs when each variable cost is considered. As sales volumes increase or decrease, there would be a concomitant increase or decrease in variable costs. Eskom is obliged to implement the High Court judgement related to the Eskom review of the NERSA RCA decisions for FY2015 to FY2017, on this matter.

2.5 Production Plan

Enormous pressure has been put on Eskom coal fired power stations to meet the demand during FY2023. It should be noted that load shedding to the extent of approximately 13 TWh was experienced. A significant shortfall in the assumptions made on independent power producers (IPPs) was experienced. This resulted in major challenges in trying to address load shedding in a bid to minimise load shedding where both Eskom and IPP OCGT's contributed.

The original decision by Government Departments proposed that approximately 35TWh of energy will be secured from IPPs (June 2021). By January 2022, the total energy from IPPs dropped to 25TWh. This moved further downwards to 20TWh when NERSA made its revenue decision. The actual turned out to be even further lower, of about 18TWh. Thus, the difference from the originally anticipated IPP energy was almost 50%.

For the June 2021 revenue application, the assumption was that coal fired power stations would provide 169 TWh of energy. This was increased to 173 TWh (Jan 2022) and in its decision (Feb 2022), NERSA further increased this energy requirement to 178 TWh. This is to meet the shortfall in the IPP energy. Eskom exceeded the energy from coal fired power plants originally assumed and achieved over 99.9% of the updated production plan.

The utilisation of Eskom OCGTs was originally 211 GWh for FY2023 (June 2021). An update due to reasons provided above, showed that a revision to at least 1 466GWh was necessary. NERSA's decision was half of this. The actual, utilised in terms of the MYPD methodology, was a little over 3TWh.

2.6 Primary energy variances

A variance of R19 556m was evidenced for primary energy which excludes variances in environmental levy, IPPs and international purchases. The total coal burn variance is R2 070m in favour of the consumer, comprising a price variance R1 654m and volume variance of R416m when comparing actuals to decision. Thus, the coal utilised for the production of electricity was secured at a lower price than the NERSA determination and the volume of coal utilised was slightly lower than determined in the decision.

It is submitted that the System Operator has dispatched OCGTs in accordance with the NERSA regulatory rules and codes. The variances between the assumptions in the decision and actuals for FY2023 illustrate the need for the use of OCGTs to the extent required to minimise the impact of loadshedding on the South African economy. The overall economic impact of loadshedding has thus been minimised. The variance for Eskom OCGT fuel accounts for a variance of R 17 602m in favour of Eskom.

For Eskom OCGT the variance in the average diesel price was approximately R2 000/MWh higher than the NERSA assumption. This resulted in a price variance of R5.9bn. The volume variance accounts for R11.7bn due to further 2 285 GWh being secured from Eskom OCGTs. The total variance being applied for is R17.6bn in the RCA balance. For IPP OCGTs, a variance of R5bn is applied for. This relates to a further 500GWh from IPP OCGTs. These costs are offset by other IPP programmes that did not materialise. In the absence of the utilisation of this variance in both Eskom and IPP OCGTs, further approximately 20% loadshedding would have been experienced.

Start-up fuel-oil variances contribute R5 121m in favour of Eskom to the RCA balance. Heavy fuel oil is used for start-ups at coal fired power station and stabilises the boiler flame on occasion. The fuel oil usage is ordinarily driven by unit start-ups/shutdowns, combustion support, safety & maintenance. However, there are also abnormal events which results in additional fuel oil usage. The number of unplanned outages and trips were significantly higher in FY2023 compared what was anticipated at the time of the MYPD5 revenue application. The average price variance is R5.21/litre which accounts for R3.2bn. The volume variance of 210million litres accounts for R1.89bn.

2.7 Regulatory Asset Base (RAB) Adjustments

Eskom has maintained the decision RAB value for depreciated replacement value of existing RAB. The High Court order related to the correction of the FY2023 RAB value refers. The joint order requires the correction of the RAB value, in accordance with the NERSA methodology, in subsequent decisions by NERSA. The variances in the return on assets was determined to be R711m and depreciation of R2 830m in favour of Eskom. This is due to significant variances in the commissioning of Eskom's Generation, Transmission and Distribution capital projects occurred during FY2023 in comparison to the decision. NERSA had determined that no transfers to commercial operation in Generation will be made in this financial year. However, that is not the case. For both Transmission and Distribution, the transfer to commercial operation was lower than the decision.

2.8 Operating expenditure variances

The overall operating costs variance, after adjustments, is in favour of Eskom by a very slight amount of R193m. All elements of operating costs, with the exception of Corporate Services and other income illustrates variances in favour of Eskom. The key reason for this is that some operating activities have migrated to operating licensees from the Corporate Divisions. A key adjustment was for arrear debt, where NERSA has decided that arrear debt recovery will not be included in the revenue determination. Even within the employee benefits category, the number of employees has decreased over the financial year. This is an area where further efficiencies have been achieved over the financial year. However, due to both the nature of the original employee benefit revenue decision as well collective bargaining agreements over multiple years with Eskom's bargaining unit employees, the resulting employee benefits costs did not see a concomitant alignment. Maintenance variances in favour of Eskom were observed due in instances to conditions beyond the control of Eskom. Significant variances were experienced within Corporate Services for the benefit of consumers.

2.9 Addressing corruption recovery

As guided by NERSA, Eskom continues to make efforts to recover any funds related to corrupt or fraudulentt activity and transactions. This is an ongoing process and very dependent on the relevant authorities finalising investigations and legal processes. No direct recoveries occurred during this period under review. Details on the initiatives to address fraud and corruption are provided in this document.

2.10 Conclusion

This RCA application is centered around the country trying to balance the supply with the demand for electricity. The production plan demonstrates that only 50% of the anticipated energy supply by independent power producers materialised. The Eskom coal fired power, despite their availability, were overwhelmed and performed at extreme energy utilisation factors. This resulted in producing over 99% of anticipated energy. The nature of coal plant operations required further use of start-up fuel to continue to contribute towards meeting the demand. The only option left to continue to try to minimise load shedding was the utilisation of OCGT – both Eskom and IPPs. This resulted in a significant RCA balance applications. The variance for Eskom OCGT fuel is R17.6bn for the favour of Eskom. The outcome for the country was unfortunately over 13TWh of load shedding, which manifests in approximately R20bn adjustment for the benefit for the consumer. The resultant overall RCA balance application is R9m.

3 Legislation and Policy

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

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

Prescribes tariff principles including:

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

3.2 Electricity Pricing Policy (EPP)

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

3.3 Government Support Framework Agreement

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

In addition, Eskom is required to seek financial support from Government to meet its payment obligations to the relevant IPPs. This could occur in the event that NERSA defers the recovery or does not permit for the recovery of these amounts required to be paid or already paid to IPPs in accordance with the contractual obligations made.

3.4 Multi-Year Price Determination (MYPD) Methodology

The revenue application is based on the requirements of the MYPD methodology as published by NERSA during October 2016. The MYPD methodology addresses two broad aspects, namely, the MYPD allowed revenue application and the adjustment of the allowed revenue through the regulatory clearing account (RCA) process. **The focus of this application is the MYPD RCA adjustments for the 2023 financial year**.

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

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

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

3.5 NERSA Guidelines for Prudency assessment

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

3.6 Eskom Retail Tariff and Structural Adjustment (ERTSA) Methodology

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

3.7 High Court Judgement on review of NERSA FY2015-2017 RCA decisions (case number 10026/2019)

Eskom has successfully reviewed the three RCA decisions for non-compliance to the MYPD Methodology and non-alignment with prior NERSA decisions. The elements of the judgement are considered in Eskom FY2023 RCA application.

The Judgement delivered on 29 June 2020, set aside the NERSA decision and found that the failure to process the decisions within a reasonable time was inconsistent with the Constitution. In addition, it found that there were fundamental factual errors as well as that the decisions made were not rational. The Judgement accepts that Eskom had put forward a proper case for relief in those key areas where NERSA did not implement its methodology. The areas specifically dealt with are the treatment of revenue variances, coal costs, Independent Power Producer costs and the capital expenditure clearing account.

3.7.1 The extract from the Judgement is as follows:

“It has been demonstrated in the founding affidavit that the bulk of the disallowed amounts claimed by Eskom fall under four headings

- *Disallowed recoveries owing to lower than forecasted revenue*
- *Disallowed coal costs*
- *Disallowed costs of procuring energy from IPPs*
- *Disallowed amounts claimed in respect of capital expenditure*

There is in respect of each of these grounds a proper case advanced on the papers which in each instance suggest that the Respondent (NERSA) disallowed costs that should not have been disallowed.

In respect of forecasted sales by way of example it disallowed R11.2711bn in respect of the variance between the forecasted and actual sales on the basis that any variance in respect of proportional primary energy costs would not be recoverable. While there is logic in what it purported to do in that if there is less electricity generated, the primary energy would reduce, what it overlooked however was that Eskom had already deducted such primary energy costs and it was therefore impermissible for NERSA to do it again.

It appears to that extent that the decision was premised on a fundamental factual error.

With regards to coal costs, NERSA disallowed the sum of R3.1bn and it did so on the basis that Eskom should have purchased coal under cost plus contracts rather that short- and *medium-term contracts and it deducted what it considered to be the difference what was it says should have spent as opposed to what it actually spent.*

Eskom says that it was unable to procure coal via cost plus contracts because of the under investment in cost plus mines which occurred as a result of a Government request. It therefore argues that it would not be open to it under these circumstances to procure from cost plus mines for this reason. The decision to disallow such ***costs was therefore not rational.***

I do not propose to deal with other grounds for review, satisfied that what is before me and on the grounds that I have dealt with, a proper case for relief has been advanced.

I make the following order:-

1. It is declared that the respondent (NERSA)

   a. Failed to process Eskom's application for approval of RCA balance for the 2015 to 2017 financial years within a reasonable time; and

   b. In so doing, acted in a manner that was inconsistent with the constitution;

2. The decisions taken by NERSA on 14 July 2018 (the NERSA RCA decisions) to approve RCA balances (Details provided) are hereby reviewed and set aside

3. It is declared that the order in prayer 2 above shall not affect the validity of the decision of NERSA on 26 September 2018 authorising Eskom to liquidate particular amounts of the RCA balance over the 2019/20 to 2023/24 financial years.

4. NERSA is ordered to pay costs including the cost of two counsel."

This Judgement confirms that Eskom's RCA applications, with regards to the four grounds that formed the basis of the review application, was indeed a correct interpretation of the MYPD methodology. Thus, Eskom has maintained its approach in this RCA application.

4 Order - Review of FY2023 revenue decision

Eskom had reviewed the NERSA FY2023 revenue decision. The focus is on the correction of the NERSA treatment of the regulatory asset base. NERSA agreed to the High Court order below. Unfortunately, some aspects of the Court order were not implemented in the subsequent NERSA revenue decision for FY 2024 and 2025.

High Court order:

1 The decision of NERSA of 24 February 2022 in relation to the Regulatory Asset Base (RAB) valuation is reviewed and set aside.

2 The order in prayer 1 above will have no retrospective effect on the 9.61% price increase granted to Eskom by NERSA for the 2022/23 tariff year.

3 NERSA is ordered to apply the 2016 methodology for the re-determination of the Regulatory Asset Base value for subsequent years after FY 2023/24

4 The RAB value, as determined by NERSA for FY 2022/23 using the steps undertaken, must be reviewed and decided on as reflected below in paragraph 6.

5 This re-determined RAB valuation for FY 2022/23 will form the basis of the RAB valuation for FY 2023/24 and FY 2024/25.

6 The steps undertaken by NERSA in the determination of the FY 2022/23 to be reviewed and decided are:

6.1 NERSA is ordered to ensure that only commissioned assets are included in the replacement cost new (RCN) determination and that the assets with construction periods of longer than 12 months and which are still included under the 'Works Under Construction' category be valued at their book value excluding capitalised Interest During Construction, until their transfer to the category of 'commissioned assets'.

*6.2 NERSA is ordered to reverse the Flue Gas Desulphurisation ("**FGD**") adjustment incorrectly made to applicable coal fired power stations.*

6.3 NERSA is ordered to re-determine the accumulated depreciation adjustment made, including to ensure that correct remaining useful lives are used to determine the accumulated depreciation as at 31 March 2020, to ensure that power stations will not have negative RAB values but have values at 31 March 2020 commensurate with the RCN times the ratio of remaining useful life to total useful life.

6.4 NERSA is ordered to ensure that correct remaining useful lives for each year are used when the roll-forward depreciation is undertaken from 31 March 2020 to determine the RAB value as at 31 March 2022. This will further ensure that power stations will not have negative RAB values but have values at each year end commensurate with the RCN times the ratio of remaining useful life to total useful life.

6.5 NERSA is ordered to comply with the MYPD methodology with regards to the Energy Availability Factor (EAF) adjustment made for all Eskom generators.

6.6 NERSA is required to include completed Generation, Transmission and Distribution asset values that were not included in the RAB value determination made for the FY 2022/23

6.7 NERSA is required to include the book value excluding capitalised Interest During Construction of all assets with construction periods of longer than 12 months and which are still included under the

Work Under Construction ("WUC") category for Generation, Transmission and Distribution assets at 31 March 2023, in the determination of the RAB value for the FY 2022/23 (that were not included in the determination).

7 Once NERSA has re-determined the RAB value as at 31 March 2023, similar approaches (based on Eskom's revenue application for FY 2023/24 and FY 2024/25) will be used to determine the RAB valuations for these financial years.

8 Each party is to pay its own costs.

5 Revenue variance

The objective of this section is to demonstrate and explain the revenue variance. The reconciliation between the revenue disclosed in the FY2023 Eskom annual financial statement (AFS) and the actual revenue to be used for RCA purposes is demonstrated. This ensures the same reference point is used.

5.1 MYPD Methodology requirements

The regulatory clearing account (RCA) balance is calculated by determining the variances which arise by comparing the FY2023 revenue decision to the Eskom actuals for particular revenues and costs as provided for in the Methodology. The calculation of the revenue variance to be included in the RCA is in terms of paragraph 17.1.1.5 of the MYPD Methodology as shown below.

17.1.1.5 Adjusting for other costs (7) and revenue variances where the variance of total actual revenue differs from the total allowed revenue.

Footnote 7 as above: Includes but not limited to taxes and levies (as defined), sales volumes and customer number variances.

Eskom has always ensured that the approach reflected in the MYPD methodology is followed in determining the revenue variance for the RCA balance.

5.2 Revenue variance calculation

When computing the RCA balance, it is important to compare the same reference points. Eskom's AFS discloses Group and Company information. NERSA regulates substantially the Company performance with some adjustments for a like for like comparison. The table below shows the items that need to be excluded from Eskom Company revenue in order to calculate revenue variance for RCA purposes.

Table 2: Reconciliation of AFS revenue to RCA revenue

Revenue Variance (R'm)	Decision FY2023	Actuals FY2023	Variance	Cumulative Revenue Variance
Total Eskom Revenue (AFS)	250 452	259 541	(9 090)	(9 090)
Add/(deduct): RCA adjustments		13 734	(13 734)	
IFRS 15 adjustment reversed (Unrecognised Revenue)		8 210	(8 210)	(17 300)
Internal electricity costs		842	(842)	(18 142)
Demand Response & Power buy back reallocated to PE		298	(298)	(18 440)
Non electricity revenue		(1 430)	1 430	(17 010)
Capitalised revenue		-	-	(17 010)
Capitalised costs associated with capitalised revenue		-	-	(17 010)
RCA liquidation included in the Actual Revenue		(13 926)	13 926	(3 084)
Power buy back		-	-	
Load shedding (13477 GWh @ 146,48 average c/kWh)		19 740	(19 740)	**(22 824)**
Electricity Revenue Variance	**250 452**	**273 276**	**(22 824)**	

5.2.1 Basis for reversal of IFRS 15 adjustment

In terms of IFRS 15, electricity revenue of R8 210m was not recognised as revenue, since it was assessed that there is a high probability that the economic benefit will not materialise (i.e. high probability that not all revenue billed will be collected). However, in terms of the MYPD methodology this revenue is added back since the sale of energy took place. Thus, the RCA includes all billed revenue, as opposed to collected revenue. Thus, Eskom's challenges with recovering all billed revenue are not a burden on consumers.

5.2.2 Basis for adjustment for internal electricity costs

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

5.2.3 Basis for demand response reallocation to primary energy

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

5.2.4 Basis for excluding non-electricity revenue

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

5.2.5 Load reduction adjustment

During FY2023 significant loadshedding and curtailment incidents were experienced. The total load reduction was determined to be a maximum of 13 477GWh. Eskom has not included the volume of energy related to loadshedding or curtailment as part of the sales volume variance.

Eskom has computed the **revenue loss impact using the principle of standard tariff rate.** The load reduction impact of **13 477 GWh is multiplied by the average standard tariff price of 146.48c/kWh.** This equates to total revenue attributable to the load reductions of **R19 740m**. The details of the overall trends in loadshedding for the financial year are explained below.

5.2.5.1 Load Shedding and curtailment

5.2.5.1.1 SUMMARY

Table 3: Loadshedding and Curtailment summary

Month	Instructed Load Shedding Hours	Instructed Load Curtailment Hours	Total Instructed Load Shedding and/or Curtailment Hours	Days on which Load Shedding and/or Curtailment Occurred	Estimated Load Reduction (GWh)
April 2022	196.8	12	196.8	11	317.3
May 2022	214.0	102	214.0	26	318.9
June 2022	186.0	11	186.0	11	480.5
July 2022	411.0	10	411.0	22	1 002.6
Aug 2022	75.0	-	75.0	7	128.9
Sep 2022	570.0	361	570.0	25	1 543.2
Oct 2022	520.5	236	535.5	28	955.8
Nov 2022	619.4	32	619.4	30	1 027.4
Dec 2022	698.0	44.5	698.0	31	1 951.5
Jan 2023	730.3	24	730.3	31	2 076.4
Feb 2023	661.0	76	661.0	28	2 159.4
Mar 2023	660.4	24	660.4	30	1 514.7
Total FY2023	**5 542.4**	**932.5**	**5 557.4**	**280**	**13 476.6**

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

5.2.5.1.2 Load Shedding Overview for FY2023

For the period 1 April 2022 – 31 Mar 2023, there were a total of 280 days of load shedding and load curtailment. The load reductions were primarily due to the following conditions:

- Shortage of generation from Eskom and IPPs
- Increased unplanned unavailability.
- Limited fuel availability at peaking stations.
- The need to conserve and replenish depleted emergency resources.
- Poor coal and compromised emissions performance.

There are two key reasons why the System Operator load shed:

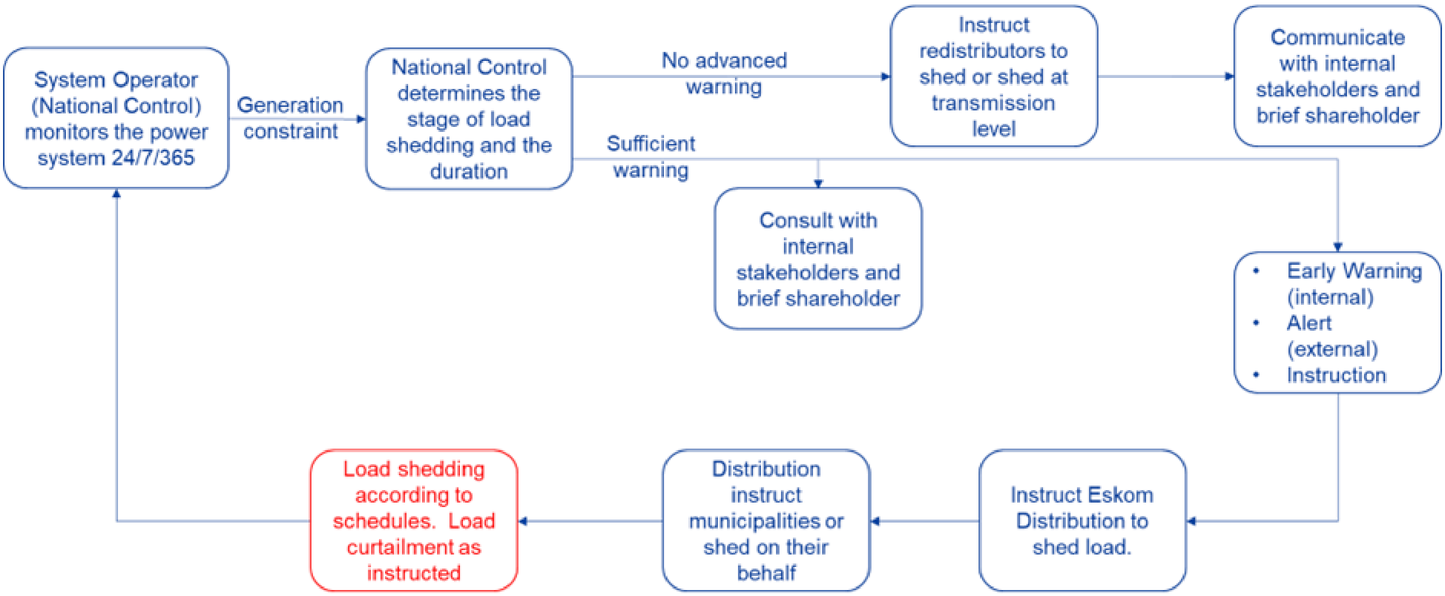
- Inadequate capacity to meet the demand.
- To enable the restoration of dam levels at Hydro Pump Storage Power stations and recovery of OCGT level. The OCGTs are being run at extremely high load factors especially during the weekend.

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

The South African Grid Code mandates the System Operator (SO) to maintain a stable grid including shedding load if necessary. The decision to shed load, especially at an escalated level, is not taken lightly and is always made with operational forethought.

The figure below shows the steps taken by SO prior to taking a decision to load shed;

Figure 1: Loadshedding Decision-making

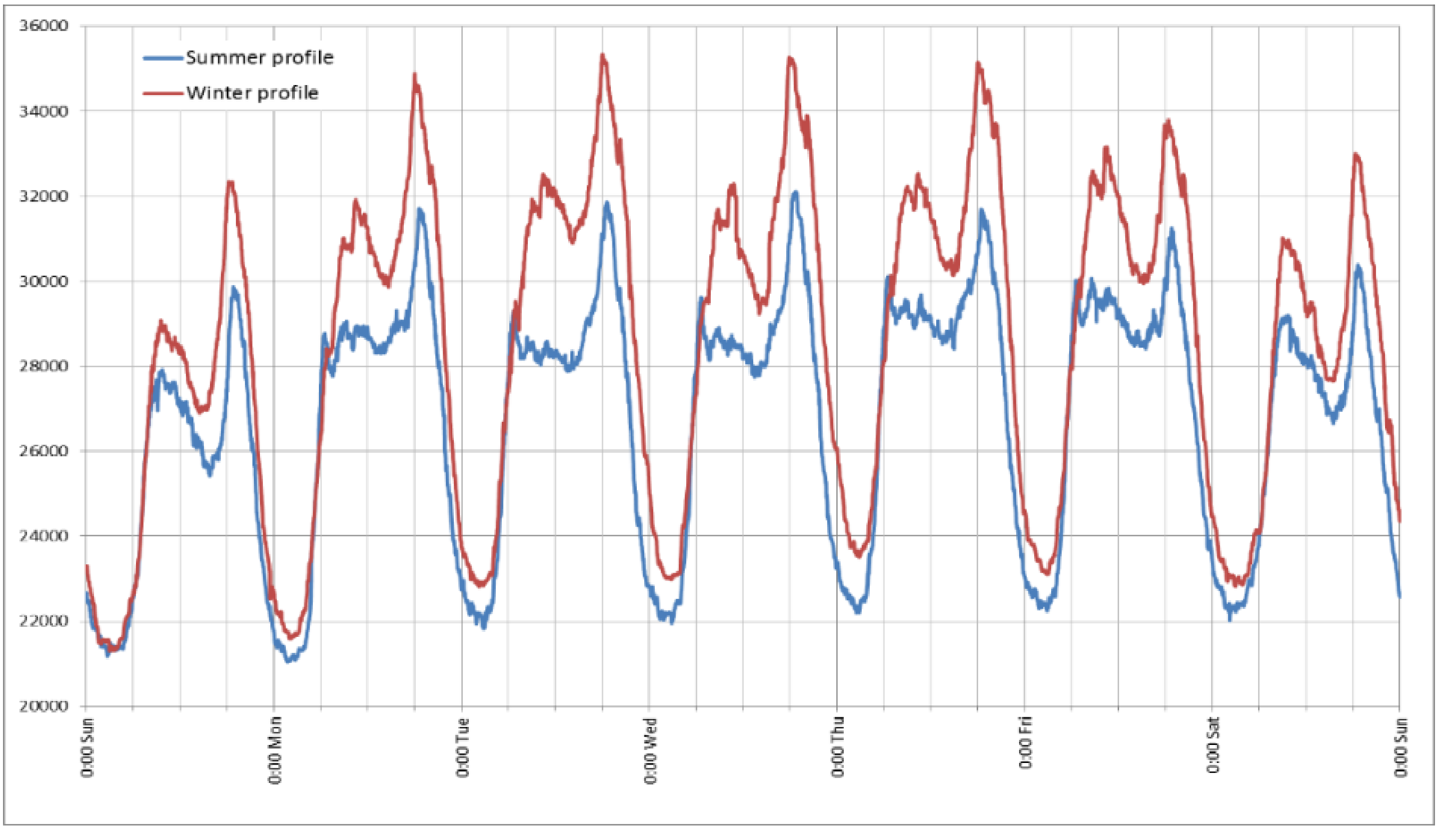


A guiding principle of implementing load reduction in terms of NRS048-9 is that all participants be treated equitably. Equitable participation is a requirement that arises from the Electricity Regulation Act which requires that customers supplied by different licensees must be treated similarly.

5.2.5.1.3 Seasonal Demand Profiles

Figure below shows the seasonal load profile. The summer load profile is a lot “flatter” than the winter profile. In winter there is a higher probability of problems over the peak periods. Peaking plant is required for many more hours during the day in summer than in winter due to the high maintenance of base load units during the summer months and the flat load profile.

Figure 2: Summer and Winter Seasonal Profile



5.2.5.1.4 Peaking gas and pumped storage usage

Prior to the start of each working week additional pumping is carried out at these stations to ensure that dams are sufficiently full to cater for generating power for peaking periods throughout the coming week, which compensates for the gradually diminishing dam levels from Monday to Friday. However, under the current system conditions, the stations are also utilised extensively outside of peaking periods to make up for the unavailability of base load plant. As a result, the respective dam levels were lower than required at various points throughout this period, thus necessitating further pumping load for dam levels to be recovered. These are some of the key drivers behind the necessity for overnight load shedding in this timeframe.

If utilised exclusively for generating, the stations would be compromised as to their capability to generate at the required level for the week ahead as required by the system (considering the compromised weekend pumping schedule and increased usage of peaking gas to support the overnight pumping load).

5.2.5.1.5 Quarter 1 (01 April – 30 June 2022)

The overview of the loadshedding and load curtailment events is structured in four quarters of the financial year.

During this quarter, the weather season transitions from autumn to the winter and temperatures begin to cool down. This is the period where the highest demand is often experienced, typically around end of May as industries ramp up production in preparation to carry out annual maintenance and save on higher winter tariffs. June is also a month that experiences some cold fronts, with high demand during these fronts, however it is still supressed by the high winter tariffs. It should be noted that easter holidays sometimes falls in this quarter and this will result in reduced demand. There were 48 days of load shedding in first quarter of the FY2023 as illustrated in the table below:

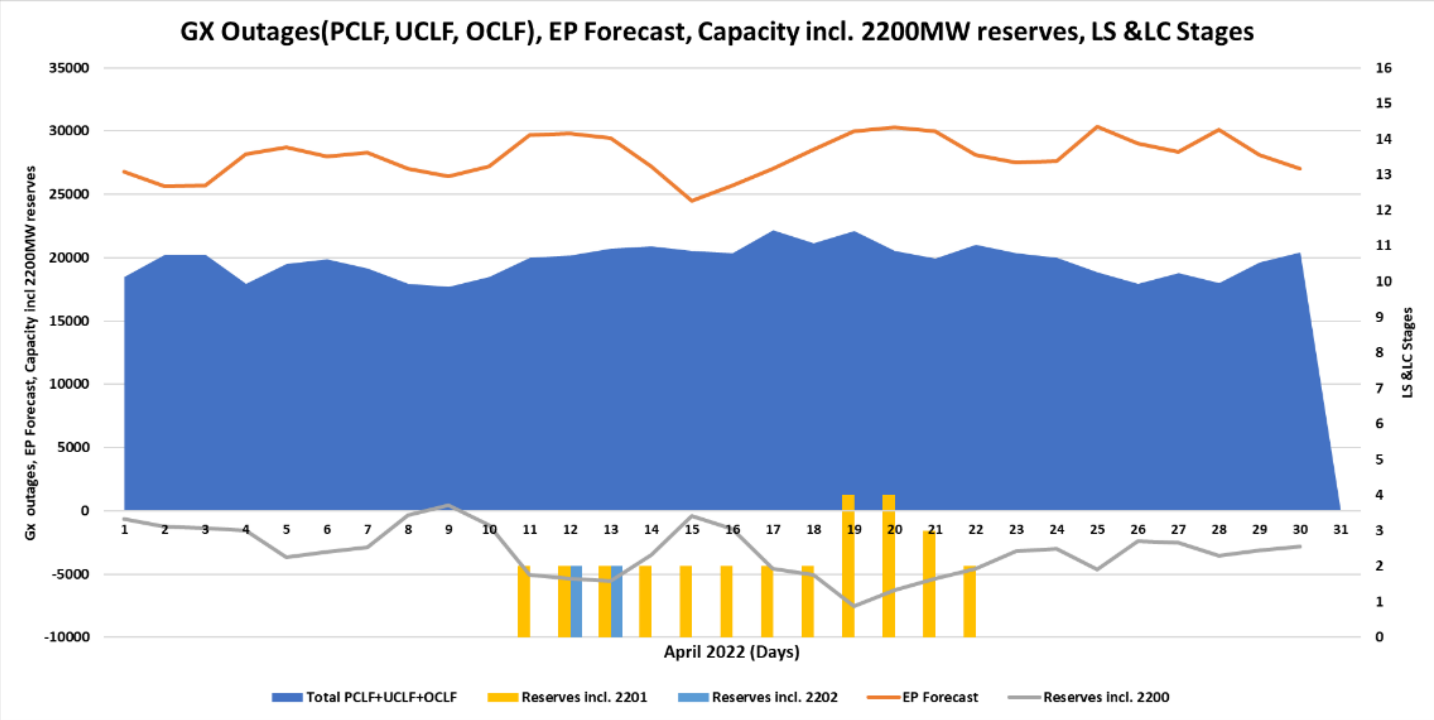
Table 4: Quarter 1 - Days of Loadshedding

Date	1st Instance																		2nd Instance							
	Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding		Stage 5 shedding		Stage 6 shedding		Curtailment stage 1/2		Curtailment stage 3		Curtailment stage 4		Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding	
	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End
Mon 11-Apr-2022			18:12	23:59																						
Tue 12-Apr-2022			00:00	05:00									17:00	23:59							17:00	23:59				
Wed 13-Apr-2022			00:00	23:59									00:00	05:00												
Thu 14-Apr-2022			00:00	23:59																						
Fri 15-Apr-2022			00:00	05:00																						
Sun 17-Apr-2022			16:00	23:59																						
Mon 18-Apr-2022			00:00	23:59																						
Tue 19-Apr-2022			00:00	07:21			07:21	23:59																		
Wed 20-Apr-2022					22:00	23:59	00:00	22:00																		
Thu 21-Apr-2022			22:00	23:59	00:00	22:00																				
Fri 22-Apr-2022			00:00	22:00																						
Tue 03-May-2022			17:00	23:59									17:00	23:59												
Wed 04-May-2022			00:00	23:59									00:00	23:59												
Thu 05-May-2022			00:00	23:59									00:00	23:59												
Fri 06-May-2022	22:00	23:59	00:00	22:00									00:00	22:00												
Sat 07-May-2022	00:00	12:00																								
Mon 09-May-2022			17:00	22:00																						
Tue 10-May-2022			17:00	22:00									17:00	22:00												
Wed 11-May-2022			17:00	22:00									17:00	22:00												
Thu 12-May-2022			17:00	22:00																						
Fri 13-May-2022	17:00	22:00																								
Sat 14-May-2022			17:00	22:00																						
Sun 15-May-2022			17:00	22:00																						
Mon 16-May-2022							17:00	22:00					17:00	22:00												
Tue 17-May-2022					17:00	22:00																				
Wed 18-May-2022			17:00	22:00																						
Thu 19-May-2022			17:00	22:00									17:00	22:00												
Fri 20-May-2022			17:00	22:00									17:00	22:00												
Sat 21-May-2022			08:00	13:00			13:00	22:00																		
Sun 22-May-2022			08:00	16:00	16:00	22:00																				
Mon 23-May-2022			17:00	22:00																						
Tue 24-May-2022			17:00	22:00																						
Wed 25-May-2022			17:00	22:00																						
Thu 26-May-2022			17:00	22:00																						
Fri 27-May-2022			17:00	22:00																						
Sat 28-May-2022	17:00	22:00																								
Mon 30-May-2022			17:00	22:00																						
Mon 20-Jun-2022			17:00	22:00																						
Tue 21-Jun-2022			17:00	22:00																						
Wed 22-Jun-2022			10:00	23:59																						
Thu 23-Jun-2022			05:00	23:59																						
Fri 24-Jun-2022			05:00	11:00			11:00	23:59																		
Sat 25-Jun-2022							05:00	23:59																		
Sun 26-Jun-2022							05:00	23:59																		
Mon 27-Jun-2022							05:00	23:59																		
Tue 28-Jun-2022							05:00	16:00			16:00	22:00													22:00	23:59
Wed 29-Jun-2022			00:00	05:00			05:00	16:00			16:00	22:00													22:00	23:59
Thu 30-Jun-2022			00:00	05:00			05:00	14:00			14:00	23:59			11:00	22:00										

i. April 2022

The following graph describes the total generation unavailability, evening peak forecast and deficit reserve capacity that contributed to the implementation of load shedding during the 1st Quarter of FY2023:

Figure 3: Total generation unavailability, forecast & reserve capacity (April 2022)



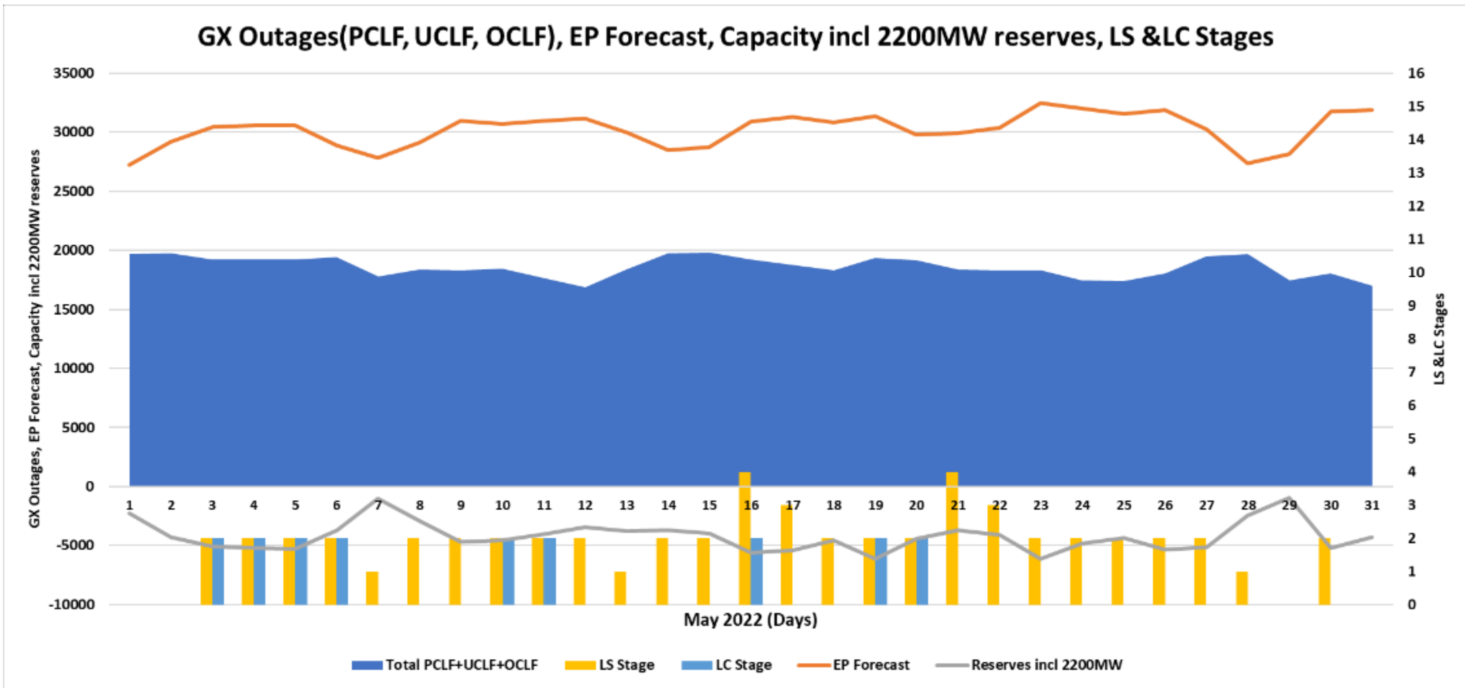
The average capacity deficit during the period 11 – 22 April was ± 2 797 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement). Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented from 11 – 22 April 2022.

ii. May 2022

The average capacity deficit during the period 01 – 31 May was ± 4 200 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement). Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented from 03 – 30 May as per NC instructions seen above.

The following graph describes the total generation unavailability, evening peak forecast and surplus reserve capacity that contributed to the implementation of load shedding during May 2022:

Figure 4: Total generation unavailability, forecast & reserve capacity (May 2022)

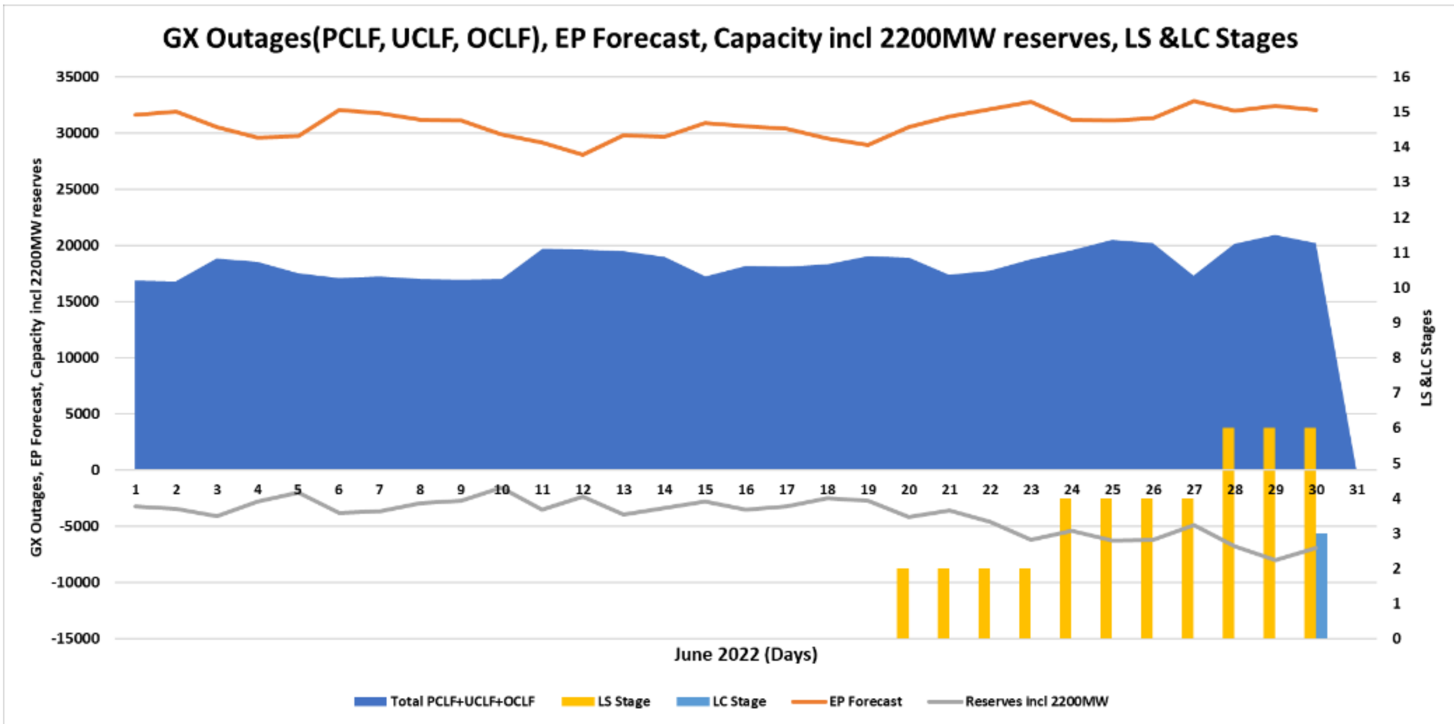


iii. June 2022

The average capacity deficit during the period 01 – 19 June was ± 3 000 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement). No load shedding as instructed during this period. However, peaking resources were heavily used from the first three weeks of June 2022 going forward based on the high levels of generation unavailability. The average capacity deficit during the period 20 – 30 June was ± 5 700 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement). Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented from 20 – 30 June as per NC instructions.

The following graph describes the total generation unavailability, evening peak forecast and surplus reserve capacity that contributed to the implementation of load shedding during June 2022:

Figure 5: Total generation unavailability, forecast & reserve capacity (June 2022)



5.2.5.1.6 Quarter 2 (01 July – 30 September 2022)

The 2nd quarter transitions from Winter to Spring. The first part of this quarter falls during the cold winter weather. The peak demand can still occur if there is a cold front, this result in high electricity demand. Towards spring, there is a lot of variability in the demand. In September, the tariffs drop again, which results is higher demand, as a lot of production picks up again. There were 54 load shedding days for the second quarter of 2022-23 financial year as shown in the table below:

Table 5: Quarter 2 - Days of loadshedding and curtailment

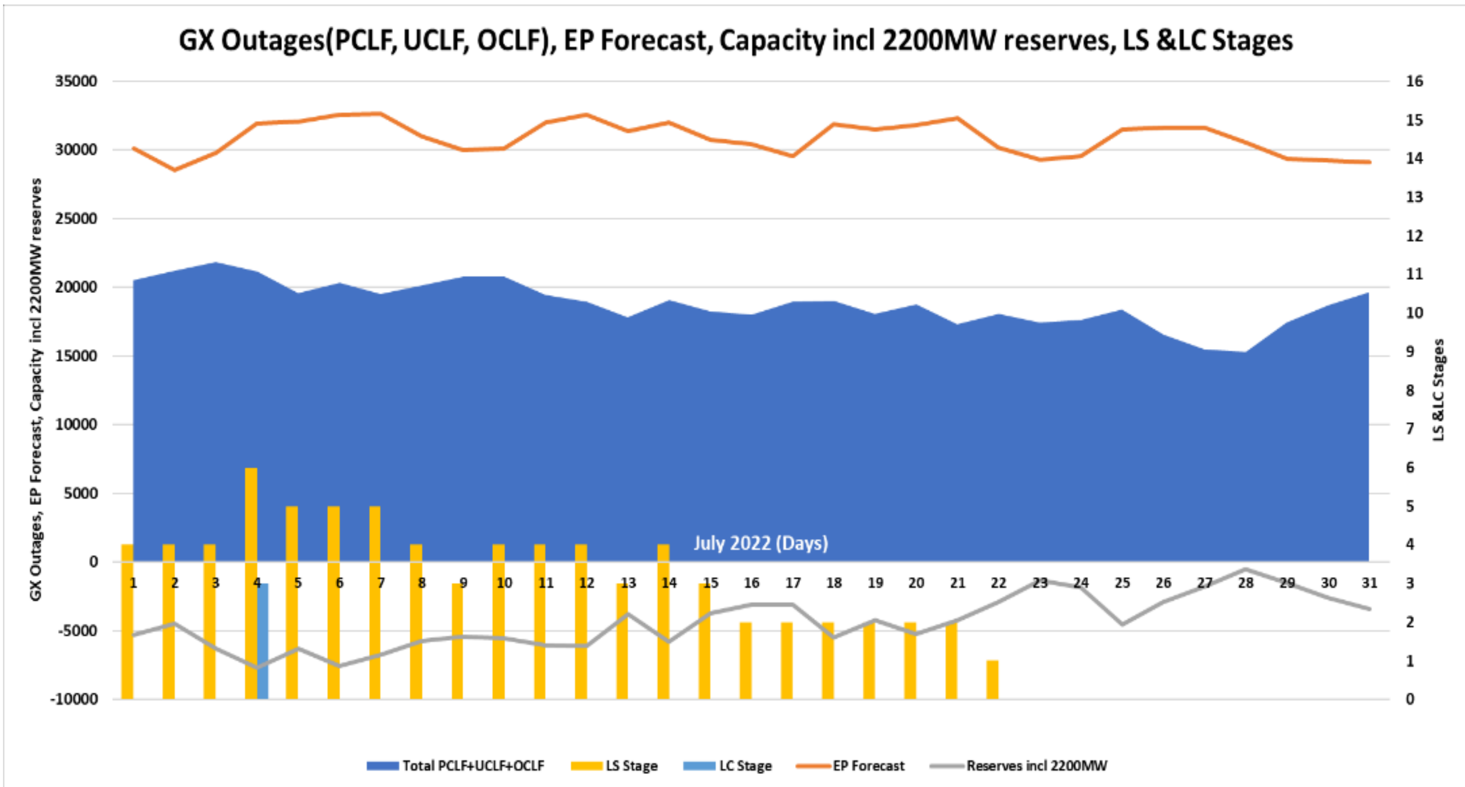
Date	1st Instance																		2nd Instance							
	Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding		Stage 5 shedding		Stage 6 shedding		Curtailment stage 1/2		Curtailment stage 3		Curtailment stage 4		Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding	
	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End
Fri 01-Jul-2022			22:00	23:59			00:00	22:00																		
Sat 02-Jul-2022			00:00	07:00			07:00	22:00													22:00	23:59				
Sun 03-Jul-2022			00:00	07:00			07:00	23:59																		
Mon 04-Jul-2022			00:00	05:00			05:00	16:00			16:00	22:00			14:00	23:59									22:00	23:59
Tue 05-Jul-2022			00:00	05:00			05:00	16:00	16:00	22:00															22:00	23:59
Wed 06-Jul-2022			00:00	05:00			05:00	16:00	16:00	22:00															22:00	23:59
Thu 07-Jul-2022			00:00	05:00			05:00	16:00	16:00	22:00															22:00	23:59
Fri 08-Jul-2022			00:00	05:00			05:00	23:59																		
Sat 09-Jul-2022			00:00	07:00	07:00	23:59																				
Sun 10-Jul-2022			00:00	07:00	07:00	16:00	16:00	23:59																		
Mon 11-Jul-2022			00:00	05:00			05:00	23:59																		
Tue 12-Jul-2022			00:00	05:00			05:00	23:59																		
Wed 13-Jul-2022			00:00	05:00	05:00	23:59																				
Thu 14-Jul-2022	00:00	05:00			05:00	16:00	16:00	23:59																		
Fri 15-Jul-2022					05:00	23:59																				
Sat 16-Jul-2022			16:00	23:59																						
Sun 17-Jul-2022			16:00	23:59																						
Mon 18-Jul-2022			16:00	23:59																						
Tue 19-Jul-2022			16:00	23:59																						
Wed 20-Jul-2022			16:00	23:59																						
Thu 21-Jul-2022			16:00	23:59																						
Fri 22-Jul-2022	16:00	23:59																								
Wed 03-Aug-2022			16:00	23:59																						
Thu 04-Aug-2022			05:00	16:00			16:00	23:59																		
Fri 05-Aug-2022			05:00	23:59																						
Sat 06-Aug-2022			16:00	21:00																						
Tue 16-Aug-2022			16:00	23:59																						
Wed 17-Aug-2022			16:00	23:59																						
Thu 18-Aug-2022			16:00	23:59																						
Tue 06-Sep-2022			16:00	22:00																						
Wed 07-Sep-2022			05:00	22:00																						
Thu 08-Sep-2022			05:00	23:59																						
Fri 09-Sep-2022			00:00	14:00	14:00	23:59																				
Sat 10-Sep-2022					00:00	10:00	10:00	23:59					11:00	23:59												
Sun 11-Sep-2022							00:00	23:59					00:00	23:59												
Mon 12-Sep-2022					05:00	23:59	00:00	05:00																		
Tue 13-Sep-2022			05:00	10:00	00:00	05:00	10:00	23:59					11:00	23:59												
Wed 14-Sep-2022							00:00	23:59					00:00	23:59												
Thu 15-Sep-2022							00:00	23:59					00:00	05:00												
Fri 16-Sep-2022							00:00	23:59																		
Sat 17-Sep-2022							00:00	10:00	10:00	23:59							11:00	23:59								
Sun 18-Sep-2022									00:00	04:16	04:16	23:59					00:00	23:59								
Mon 19-Sep-2022											00:00	23:59	22:00	23:59			00:00	22:00								
Tue 20-Sep-2022									00:00	23:59			00:00	23:59												
Wed 21-Sep-2022									00:00	23:59			00:00	23:59												
Thu 22-Sep-2022									00:00	23:59			00:00	23:59												
Fri 23-Sep-2022									00:00	23:59			00:00	23:59												
Sat 24-Sep-2022							05:00	23:59	00:00	05:00			00:00	05:00												
Sun 25-Sep-2022					05:00	23:59	00:00	05:00																		
Mon 26-Sep-2022					00:00	16:00	16:00	23:59					00:00	23:59												
Tue 27-Sep-2022					00:00	16:00	16:00	23:59					00:00	23:59												
Wed 28-Sep-2022					00:00	16:00	16:00	23:59					00:00	22:00			22:00	23:59								
Thu 29-Sep-2022							00:00	23:59									00:00	23:59								
Fri 30-Sep-2022							00:00	23:59									00:00	23:59								

The following graphs describes the total generation unavailability, evening peak forecast and deficit reserve capacity that contributed to the implementation of load shedding during Quarter 2 of a financial year 2023:

iv. July 2022

The average capacity deficit during the period 01 – 23 July was ± 5 200 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement). Due to this shortfall in generation capacity and in order to conserve the compromised peaking resource levels, load shedding was implemented from 01 – 23 July 2022. The average capacity deficit during the period 24 – 31 July was ± 2 200 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement). No load shedding was implemented during this period. However, peaking resources were heavily used from the last week of July 2022 going forward based on the high levels of generation unavailability.

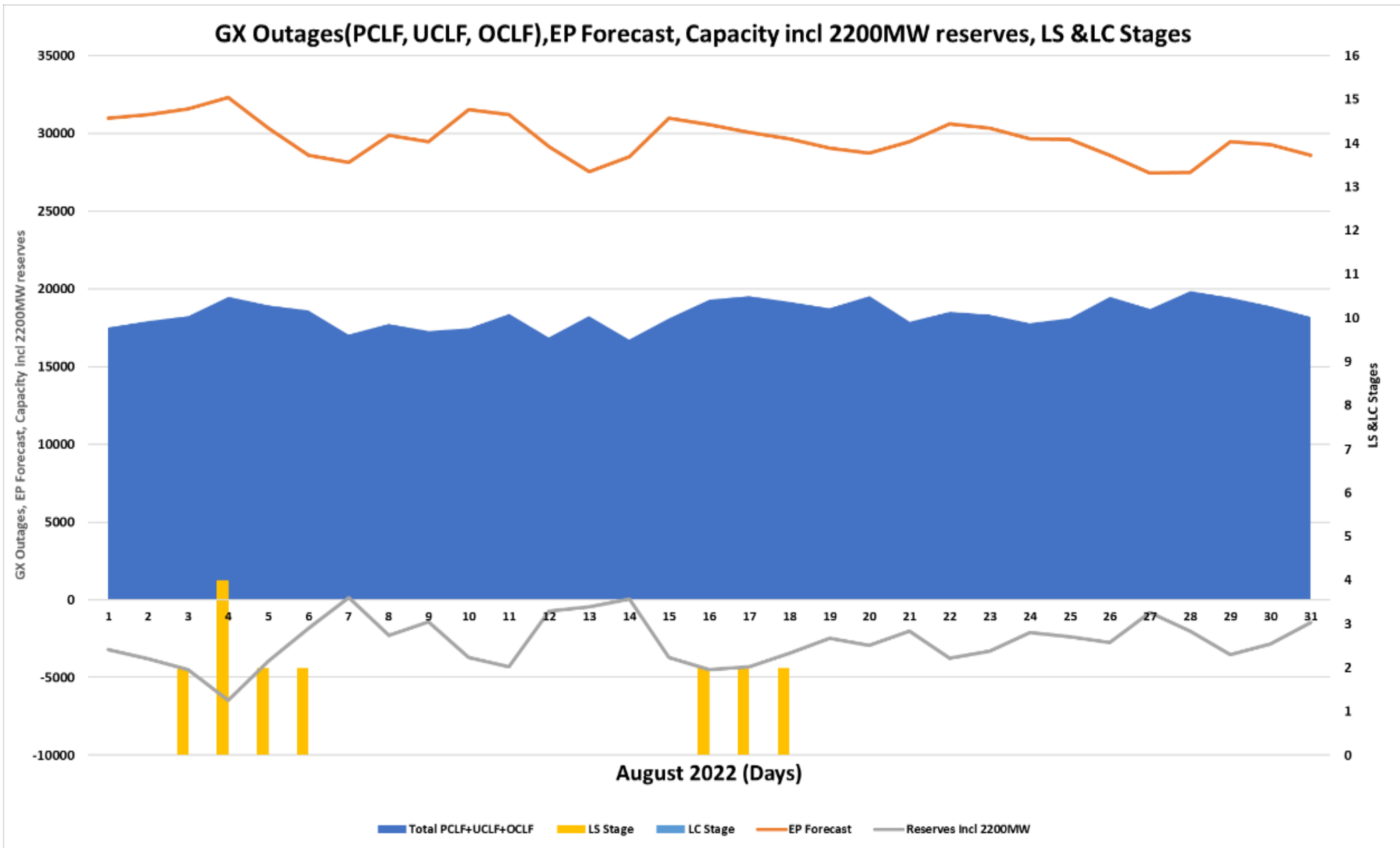
Figure 6: Total generation unavailability, forecast & reserve capacity (July 2022)



v. August 2022

The average capacity deficit during the periods 03 – 05 August 2022 and 16 – 18 August were ± 5 000 MW and ± 4 000 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement). Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented from 03 – 06 and 16 – 18 August.

Figure 7: Total generation unavailability, forecast & reserve capacity (August 2022)

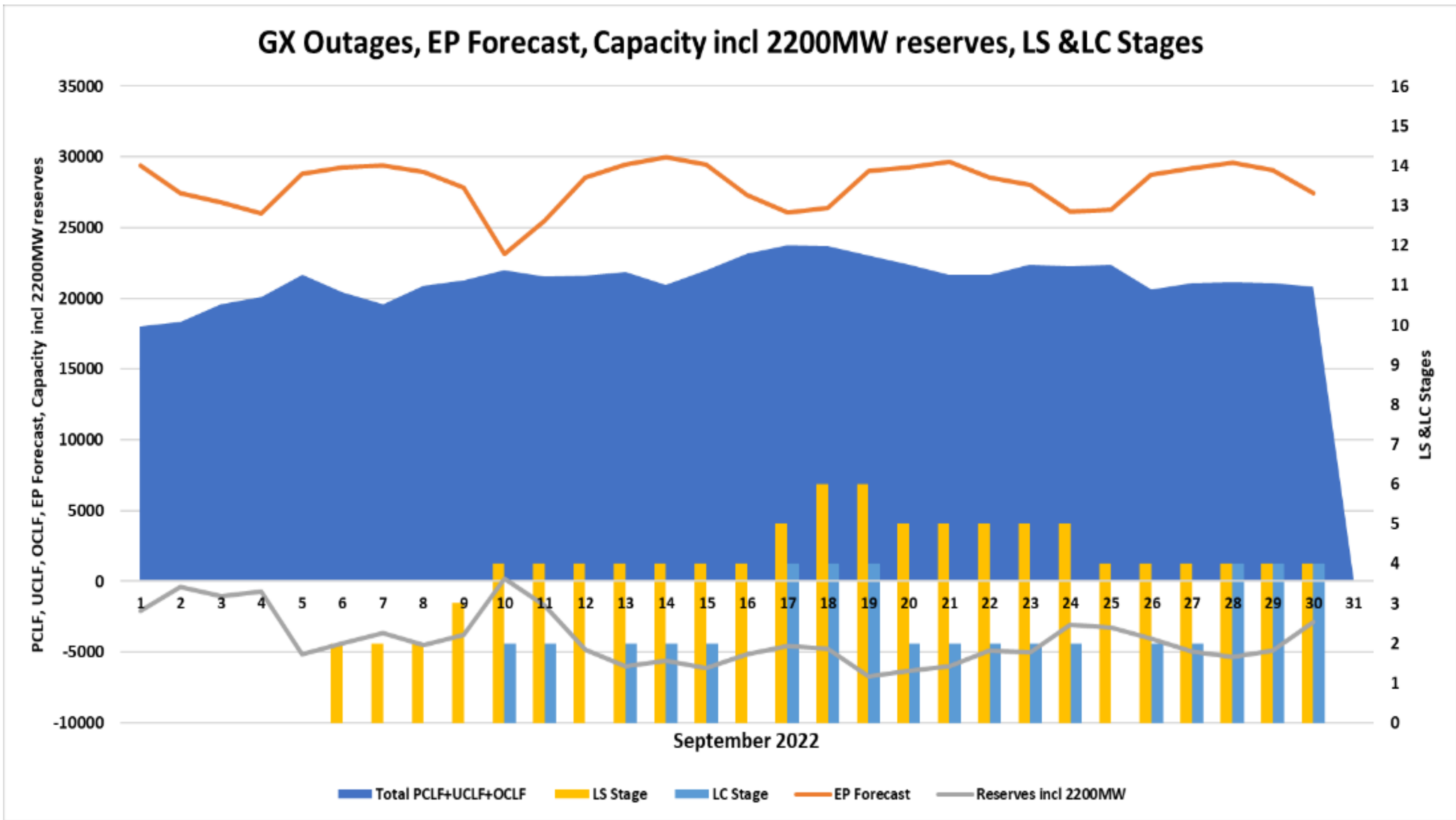


vi. September 2022

The average capacity deficit during the period 01 – 30 September was ± 4 000 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement) and peaked at ± 6 700 MW. Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented from 06 – 30 September.

The weekend of the 2nd of September 2022 experienced a high number of generator breakdowns. The total generation outages peaked at 21 600 MW. Unit each at Koeberg, Kendal, Arnot, Matla, Majuba, Duvha, Kusile and two units at Hendrina power stations were taken offload for different reasons. Furthermore, during the weekend of 16 September 2022, generation outages was averaging 23 000 MW and peaked at 23 787 MW. This resulted in higher stages of load shedding as depicted in the figure below. The units at Kendal, Tutuka, Kusile, Arnot, Majuba, Kriel, Camden, Duvha were taken off for number of reasons.

Figure 8: Total generation unavailability, forecast & reserve capacity (September 2022)



5.2.5.1.7 Quarter 3 (01 October – 31 December 2022)

The seasonal transition from spring to summer with predominantly hot weather and an increase in rainfall can cause demand variations. The morning and evening peaks are not as high as the preceding quarters. Aircon load starts to pick-up with the higher temperatures, however, of late this has been offset greatly by the rooftop PVs, generating at higher levels due the increased irradiation. The demand drop significantly by mid-December as the schools are closed and most companies and industries close for the holidays. There were 89 load shedding days for the 3rd quarter of 2023 financial year as shown below

Table 6: Quarter 3 - Days of loadshedding and curtailment

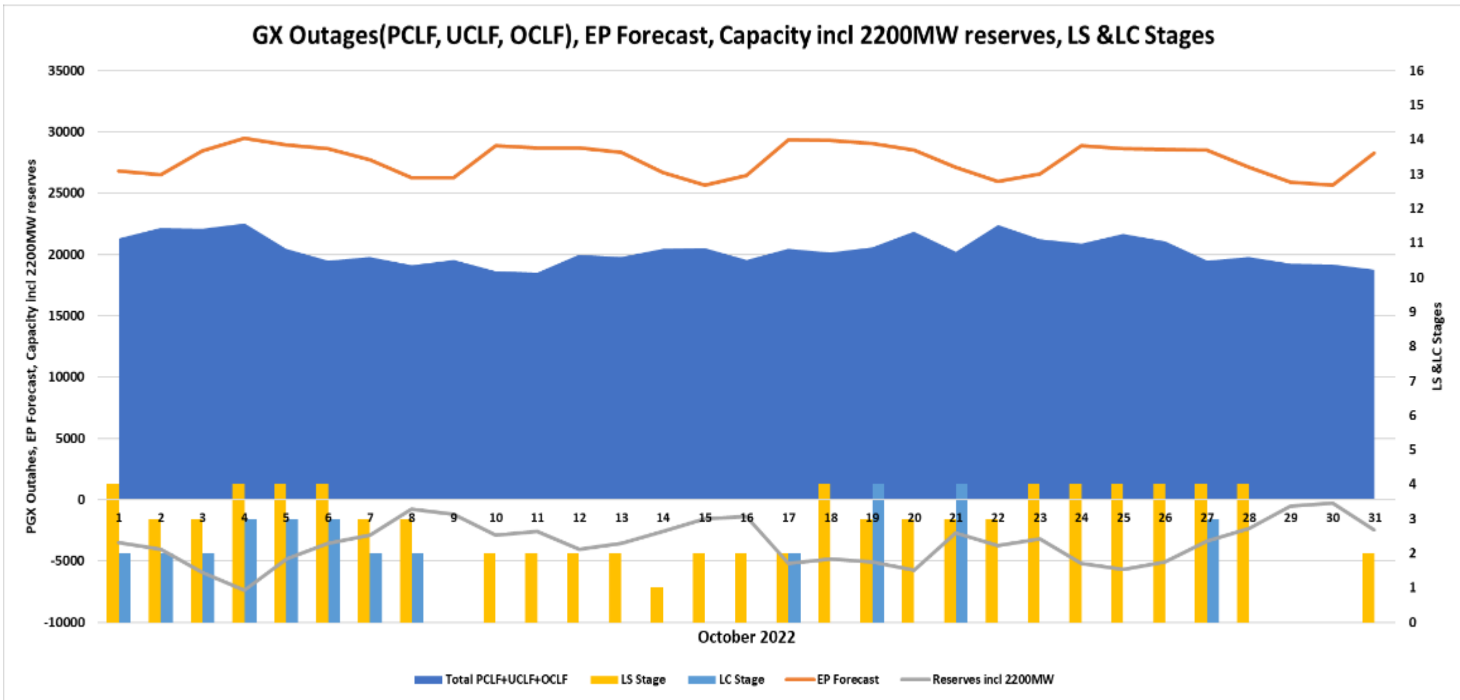
Date	1st Instance																		2nd Instance							
	Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding		Stage 5 shedding		Stage 6 shedding		Curtailment stage 1/2		Curtailment stage 3		Curtailment stage 4		Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding	
	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End
Sat 01-Oct-2022					05:00	23:59	00:00	05:00					00:00	23:59												
Sun 02-Oct-2022					00:00	23:59							00:00	23:59												
Mon 03-Oct-2022					00:00	23:59							00:00	23:59												
Tue 04-Oct-2022					00:00	18:00	18:00	23:59					00:00	20:00	20:00	23:59										
Wed 05-Oct-2022							00:00	23:59							00:00	23:59										
Thu 06-Oct-2022					05:00	23:59	00:00	05:00					05:00	23:59	00:00	05:00										
Fri 07-Oct-2022					00:00	23:59							00:00	23:59												
Sat 08-Oct-2022					00:00	05:00							00:00	05:00												
Mon 10-Oct-2022			16:00	23:59																						
Tue 11-Oct-2022			16:00	23:59																						
Wed 12-Oct-2022			16:00	23:59																						
Thu 13-Oct-2022			16:00	23:59																						
Fri 14-Oct-2022	16:00	23:00																								
Sat 15-Oct-2022			14:00	23:59																						
Sun 16-Oct-2022			00:00	23:59																						
Mon 17-Oct-2022			16:00	23:59									12:00	23:59												
Tue 18-Oct-2022							05:30	23:59																		
Wed 19-Oct-2022			00:00	05:00	16:00	23:59											05:00	22:00								
Thu 20-Oct-2022					00:00	23:59																				
Fri 21-Oct-2022					00:00	23:59											05:00	22:00								
Sat 22-Oct-2022					00:00	23:59																				
Sun 23-Oct-2022					00:00	12:00	12:00	23:59																		
Mon 24-Oct-2022					05:00	16:00	00:00	05:00																	16:00	23:59
Tue 25-Oct-2022					05:00	16:00	00:00	05:00																	16:00	23:59
Wed 26-Oct-2022					05:00	16:00	00:00	05:00																	16:00	23:59
Thu 27-Oct-2022					05:00	16:00	00:00	05:00							05:00	22:00									16:00	23:59
Fri 28-Oct-2022			05:00	16:00	16:00	23:59	00:00	05:00																		
Mon 31-Oct-2022			05:00	23:59																						
Tue 01-Nov-2022			00:00	05:00																	16:00	23:59				
Wed 02-Nov-2022	05:00	16:00	16:00	23:59																						
Thu 03-Nov-2022	04:00	16:00	00:00	00:42																	16:00	23:59				
Fri 04-Nov-2022	04:00	16:00	00:00	00:32																	16:00	23:59				
Sat 05-Nov-2022	05:00	16:00	00:00	05:00																	16:00	23:59				
Sun 06-Nov-2022	05:00	11:40	00:00	05:00																						
Mon 07-Nov-2022			16:00	23:59																						
Tue 08-Nov-2022			00:00	05:00									15:00	22:00							09:00	23:59				
Wed 09-Nov-2022			00:00	23:59																						
Thu 10-Nov-2022			00:00	23:59									16:00	22:00												
Fri 11-Nov-2022			00:00	23:59																						
Sat 12-Nov-2022			00:00	23:59																						
Sun 13-Nov-2022			00:00	23:59																						
Mon 14-Nov-2022			00:00	16:00	16:00	23:59							16:00	22:00												
Tue 15-Nov-2022			05:00	21:57	00:00	05:00																				
Wed 16-Nov-2022			02:03	16:00	16:00	23:59							15:00	22:00												
Thu 17-Nov-2022			05:00	16:00	00:00	05:00																	16:00	23:59		
Fri 18-Nov-2022			05:00	05:26	00:00	05:00	05:26	23:59																		
Sat 19-Nov-2022							00:00	23:59																		
Sun 20-Nov-2022							00:00	08:01																	17:00	23:59
Mon 21-Nov-2022							00:00	23:59																		
Tue 22-Nov-2022			05:00	16:00			00:00	05:00																	16:00	23:59
Wed 23-Nov-2022			05:00	16:00			00:00	05:00																	16:00	23:59
Thu 24-Nov-2022			05:00	16:00	16:00	23:59	00:00	05:00					16:00	22:00												
Fri 25-Nov-2022			05:00	23:59	00:00	05:00																				
Sat 26-Nov-2022			00:00	22:36																						
Sun 27-Nov-2022			04:00	23:59																						
Mon 28-Nov-2022	05:00	16:00	16:00	23:59																						
Tue 29-Nov-2022			00:00	05:00																	16:00	23:59				
Wed 30-Nov-2022			00:00	05:00																	16:00	23:59				
Thu 01-Dec-2022			00:00	05:00																	16:00	23:59				
Fri 02-Dec-2022			00:00	05:00																	16:00	23:59				
Sat 03-Dec-2022			00:00	21:57			21:57	23:59																		
Sun 04-Dec-2022							00:00	23:59																		
Mon 05-Dec-2022					05:00	23:59	00:00	05:00																		
Tue 06-Dec-2022			05:00	16:00	00:00	05:00																	16:00	23:59		

Date	1st Instance																		2nd Instance							
	Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding		Stage 5 shedding		Stage 6 shedding		Curtailment stage 1/2		Curtailment stage 3		Curtailment stage 4		Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding	
	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End
Wed 07-Dec-2022			05:00	09:00	00:00	05:00	09:00	12:00			12:00	23:59					16:30	23:59								
Thu 08-Dec-2022											00:00	23:59					00:00	23:59								
Fri 09-Dec-2022									05:00	23:59	00:00	05:00					00:00	05:00								
Sat 10-Dec-2022							05:00	13:05	00:00	05:00																
Sun 11-Dec-2022									00:00	23:59																
Mon 12-Dec-2022									00:00	23:59			16:00	23:59												
Tue 13-Dec-2022									00:00	23:59																
Wed 14-Dec-2022									00:00	23:59																
Thu 15-Dec-2022							05:00	23:59	00:00	05:00																
Fri 16-Dec-2022							00:00	08:34			08:34	23:59														
Sat 17-Dec-2022											00:00	23:59														
Sun 18-Dec-2022											00:00	23:59														
Mon 19-Dec-2022									05:00	23:59	00:00	05:00														
Tue 20-Dec-2022							05:00	20:00	00:00	05:00	20:00	23:59														
Wed 21-Dec-2022							05:00	23:59			00:00	05:00														
Thu 22-Dec-2022							00:00	23:59																		
Fri 23-Dec-2022							00:00	23:59																		
Sat 24-Dec-2022					05:00	23:59	00:00	05:00																		
Sun 25-Dec-2022					00:00	05:00																				
Mon 26-Dec-2022	05:00	23:59																								
Tue 27-Dec-2022	00:00	16:00			16:00	23:59																				
Wed 28-Dec-2022			05:00	15:45	00:00	05:00	15:45	23:59																		
Thu 29-Dec-2022					05:00	16:00	00:00	05:00																	16:00	23:59
Fri 30-Dec-2022					05:00	16:00	00:00	05:00																	16:00	23:59
Sat 31-Dec-2022			05:00	23:59			00:00	05:00																		

vii. October 2022

The average capacity deficit during the period 01 – 31 October 2022 was ± 3 500 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement) and peaked at ± 7 400 MW. Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented for 27 days in October.

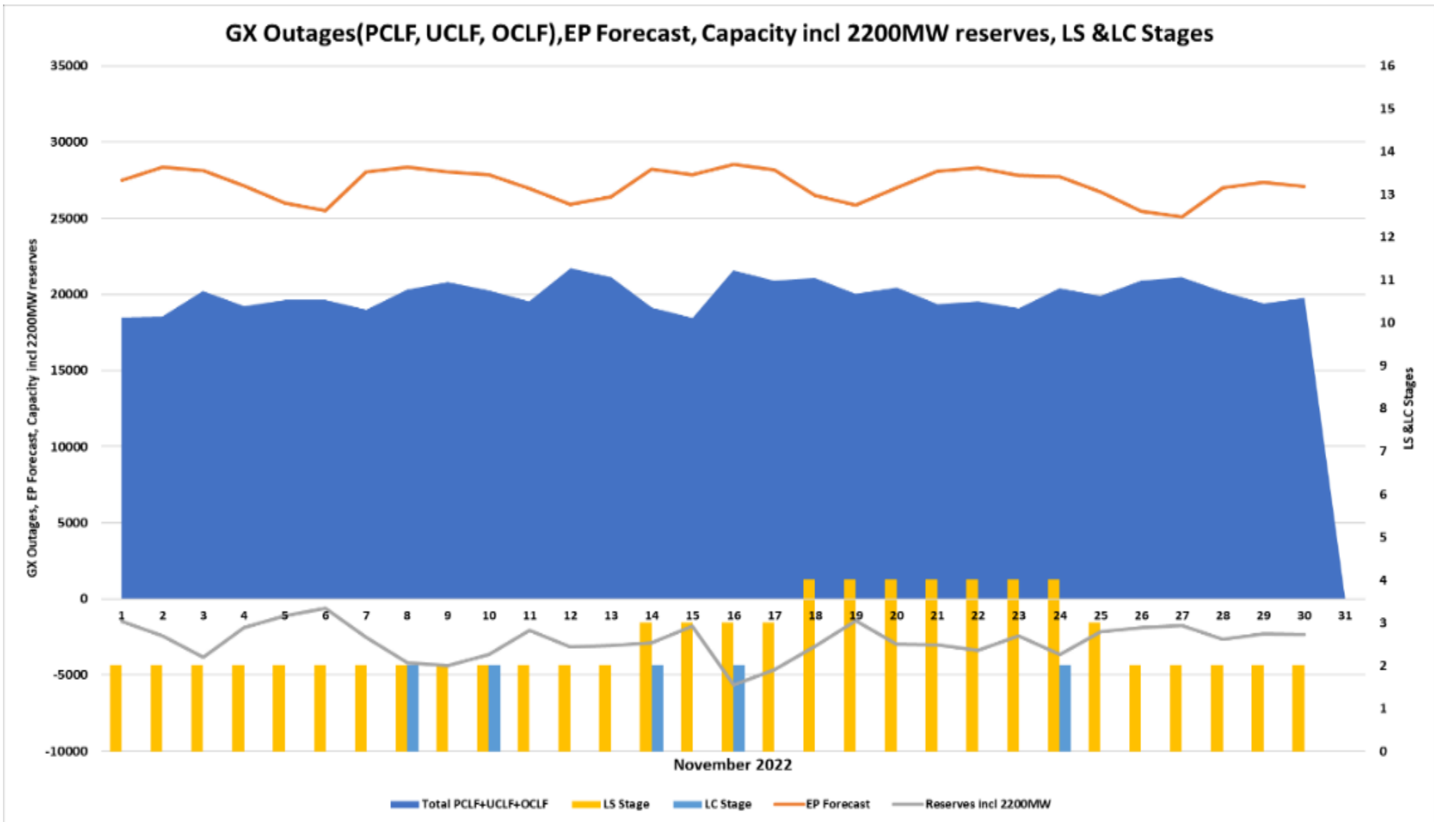
Figure 9: Total generation unavailability, forecast & reserve capacity (October 2022)



viii. November 2022

The average capacity deficit during the period 01 – 30 November was ± 2 700 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement) and peaked at ± 5 600 MW. Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented for the whole of November.

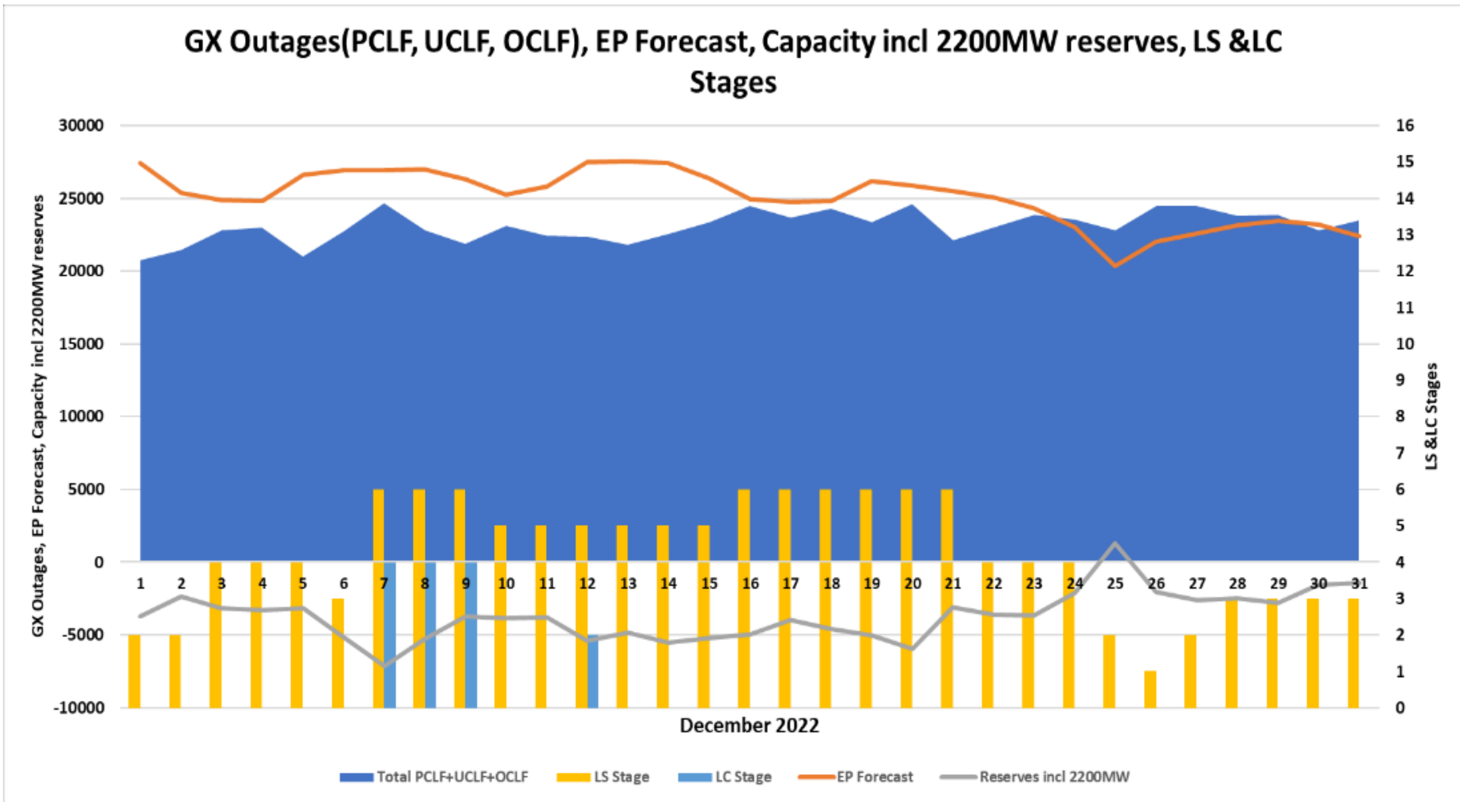
Figure 10: Total generation unavailability, forecast & reserve capacity (November 2022)



ix. December 2022

The average capacity deficit during the period 01 – 31 December was ± 3 700 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement) and peaked at ± 7 000 MW. Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented for the whole of December 2022.

Figure 11: Total generation unavailability, forecast & reserve capacity (December 2022)



5.2.5.1.8 Quarter 4 (01 January – 31 March 2023)

The final quarter of the financial year start with low demand during the holidays but picks up quickly by mid-January as the industries and schools resumes. The quarter normally experiences the highest temperatures, with the associated demand response, especially for cooling. It is also a period with higher rainfall, particularly thunderstorms due to the hot temperatures. This results in higher demand during the late afternoons. There were 89 load shedding days for the fourth quarter of FY2023, and can be summarised as shown below:

Table 7: Quarter 4 - Days of loadshedding and curtailment

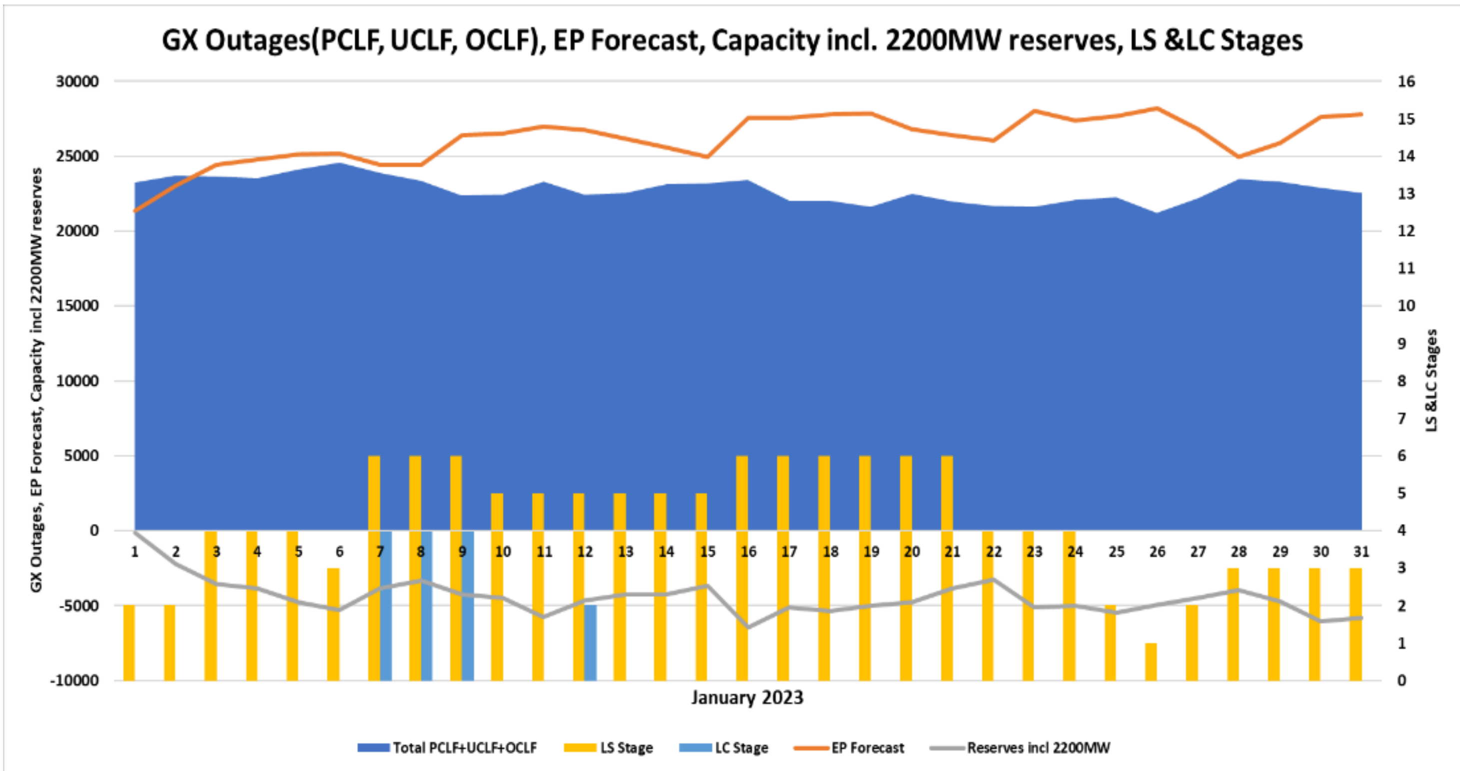
Date	1st Instance																		2nd Instance							
	Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding		Stage 5 shedding		Stage 6 shedding		Curtailment stage 1/2		Curtailment stage 3		Curtailment stage 4		Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding	
	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End
Sun 01-Jan-2023			00:00	23:59																						
Mon 02-Jan-2023			00:00	01:15																	15:00	23:59				
Tue 03-Jan-2023			00:00	23:59																						
Wed 04-Jan-2023			00:00	16:00	16:00	23:59																				
Thu 05-Jan-2023					00:00	16:00	16:00	23:59																		
Fri 06-Jan-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Sat 07-Jan-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Sun 08-Jan-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Mon 09-Jan-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Tue 10-Jan-2023					05:00	16:00	00:00	05:00			21:00	23:59													16:00	21:00
Wed 11-Jan-2023							05:00	16:00			00:00	05:00														
Thu 12-Jan-2023											00:00	23:59					14:00	22:00								
Fri 13-Jan-2023											00:00	23:59														
Sat 14-Jan-2023											00:00	23:59														
Sun 15-Jan-2023											00:00	23:59														
Mon 16-Jan-2023											00:00	23:59														
Tue 17-Jan-2023							05:00	16:00	16:00	23:59	00:00	05:00														
Wed 18-Jan-2023							05:00	16:00	00:00	05:00																
Thu 19-Jan-2023							05:00	16:00	00:00	05:00																
Fri 20-Jan-2023							05:00	23:59	00:00	05:00																
Sat 21-Jan-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Sun 22-Jan-2023			05:00	16:00	16:00	23:59	00:00	05:00																		
Mon 23-Jan-2023					00:00	16:00	16:00	23:59																		
Tue 24-Jan-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Wed 25-Jan-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Thu 26-Jan-2023							00:00	05:00	05:00	23:59							14:00	22:00								
Fri 27-Jan-2023							05:00	23:59	00:00	05:00																
Sat 28-Jan-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Sun 29-Jan-2023			05:00	16:00			00:00	05:00																	16:00	23:59
Mon 30-Jan-2023							00:00	23:59																		
Tue 31-Jan-2023							00:00	12:00	12:00	21:00	21:00	23:59					14:00	22:00								
Wed 01-Feb-2023									05:00	23:59	00:00	05:00	14:00	22:00												
Thu 02-Feb-2023									00:00	23:59			14:00	22:00												
Fri 03-Feb-2023							05:00	23:59	00:00	05:00																
Sat 04-Feb-2023					05:00	23:59	00:00	05:00																		
Sun 05-Feb-2023			16:00	23:59	00:00	05:00																				
Mon 06-Feb-2023			00:00	05:00	05:00	16:00	16:00	23:59																		
Tue 07-Feb-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Wed 08-Feb-2023					05:00	16:00	00:00	05:00					14:00	22:00											16:00	23:59
Thu 09-Feb-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Fri 10-Feb-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Sat 11-Feb-2023					05:00	23:59	00:00	05:00																		
Sun 12-Feb-2023			05:00	16:00	00:00	05:00																	16:00	23:59		
Mon 13-Feb-2023					00:00	16:00	16:00	23:59																		
Tue 14-Feb-2023					05:00	16:00	00:00	05:00					14:00	22:00											16:00	23:59
Wed 15-Feb-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Thu 16-Feb-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Fri 17-Feb-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Sat 18-Feb-2023							00:00	20:00			20:00	23:59														
Sun 19-Feb-2023							05:00	20:00			00:00	05:00														
Mon 20-Feb-2023											00:00	23:59					14:00	22:00								
Tue 21-Feb-2023											00:00	23:59					12:00	23:59								
Wed 22-Feb-2023											00:00	23:59					00:00	23:59								
Thu 23-Feb-2023											00:00	23:59														
Fri 24-Feb-2023											00:00	23:59														
Sat 25-Feb-2023											00:00	23:59														
Sun 26-Feb-2023							09:00	23:59	05:00	09:00	00:00	05:00														
Mon 27-Feb-2023							00:00	16:00	16:00	23:59																
Tue 28-Feb-2023					05:00	16:00	16:00	23:59	00:00	05:00																
Wed 01-Mar-2023							00:00	16:00	16:00	23:59																
Thu 02-Mar-2023							05:00	16:00	00:00	05:00																
Fri 03-Mar-2023							05:00	23:59	00:00	05:00																
Sat 04-Mar-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Sun 05-Mar-2023			05:00	16:00			00:00	05:00																	16:00	23:59

Date	1st Instance																		2nd Instance							
	Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding		Stage 5 shedding		Stage 6 shedding		Curtailment stage 1/2		Curtailment stage 3		Curtailment stage 4		Stage 1 shedding		Stage 2 shedding		Stage 3 shedding		Stage 4 shedding	
	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End	Start	End
Mon 06-Mar-2023							00:00	16:00	16:00	23:59			16:00	23:59												
Tue 07-Mar-2023							05:00	16:00	00:00	05:00							14:00	22:00								
Wed 08-Mar-2023							05:00	23:59	00:00	05:00																
Thu 09-Mar-2023							00:00	23:59																		
Fri 10-Mar-2023							00:00	23:59																		
Sat 11-Mar-2023					05:00	23:59	00:00	05:00																		
Sun 12-Mar-2023	05:00	16:00			00:00	05:00	16:00	23:59																		
Mon 13-Mar-2023							00:00	02:35																	05:10	23:59
Tue 14-Mar-2023							00:00	23:59																		
Wed 15-Mar-2023					05:00	16:00	00:00	05:00																	16:00	23:59
Thu 16-Mar-2023					05:00	23:59	00:00	05:00																		
Fri 17-Mar-2023			12:00	23:59	00:00	12:00																				
Sat 18-Mar-2023	05:00	23:59	00:00	05:00																						
Sun 19-Mar-2023	00:00	05:00																								
Mon 20-Mar-2023	05:00	11:00																								
Wed 22-Mar-2023			05:00	16:00	16:00	23:59																				
Thu 23-Mar-2023			05:00	16:00	00:00	05:00																	16:00	23:59		
Fri 24-Mar-2023			02:00	23:59	00:00	02:00																				
Sat 25-Mar-2023	05:00	16:00	00:00	05:00																	16:00	23:59				
Sun 26-Mar-2023	16:00	23:59	00:00	05:00																						
Mon 27-Mar-2023	00:00	01:00	05:00	16:00	16:00	23:59																				
Tue 28-Mar-2023	05:00	16:00	16:00	23:59	00:00	05:00																				
Wed 29-Mar-2023	05:00	16:00	00:00	05:00	18:11	23:59															16:00	18:11				
Thu 30-Mar-2023					00:00	16:00	16:00	23:59					14:00	22:00												
Fri 31-Mar-2023					05:00	13:12	00:00	05:00																	13:12	23:59

x. January 2023

The average capacity deficit during the period 01 – 31 January was ± 4 500 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement) and peaked at ± 6 500 MW. Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented for the whole of January 2023.

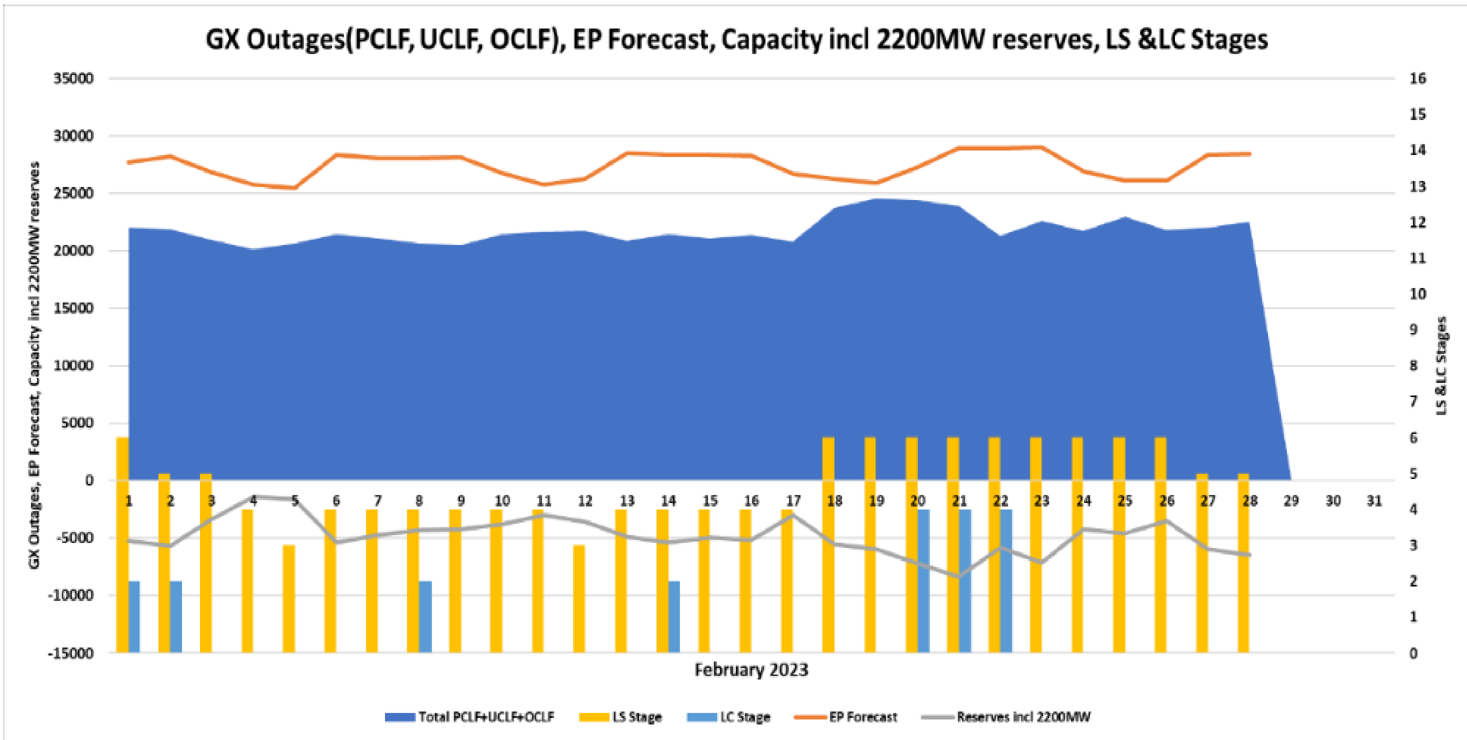
Figure 12: Total generation unavailability, forecast & reserve capacity (January 2023)



xi. February 2023

The average capacity deficit during the period 01 – 28 February was ± 4 800 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement) and peaked at ± 8 400 MW. Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented for the whole of February 2023.

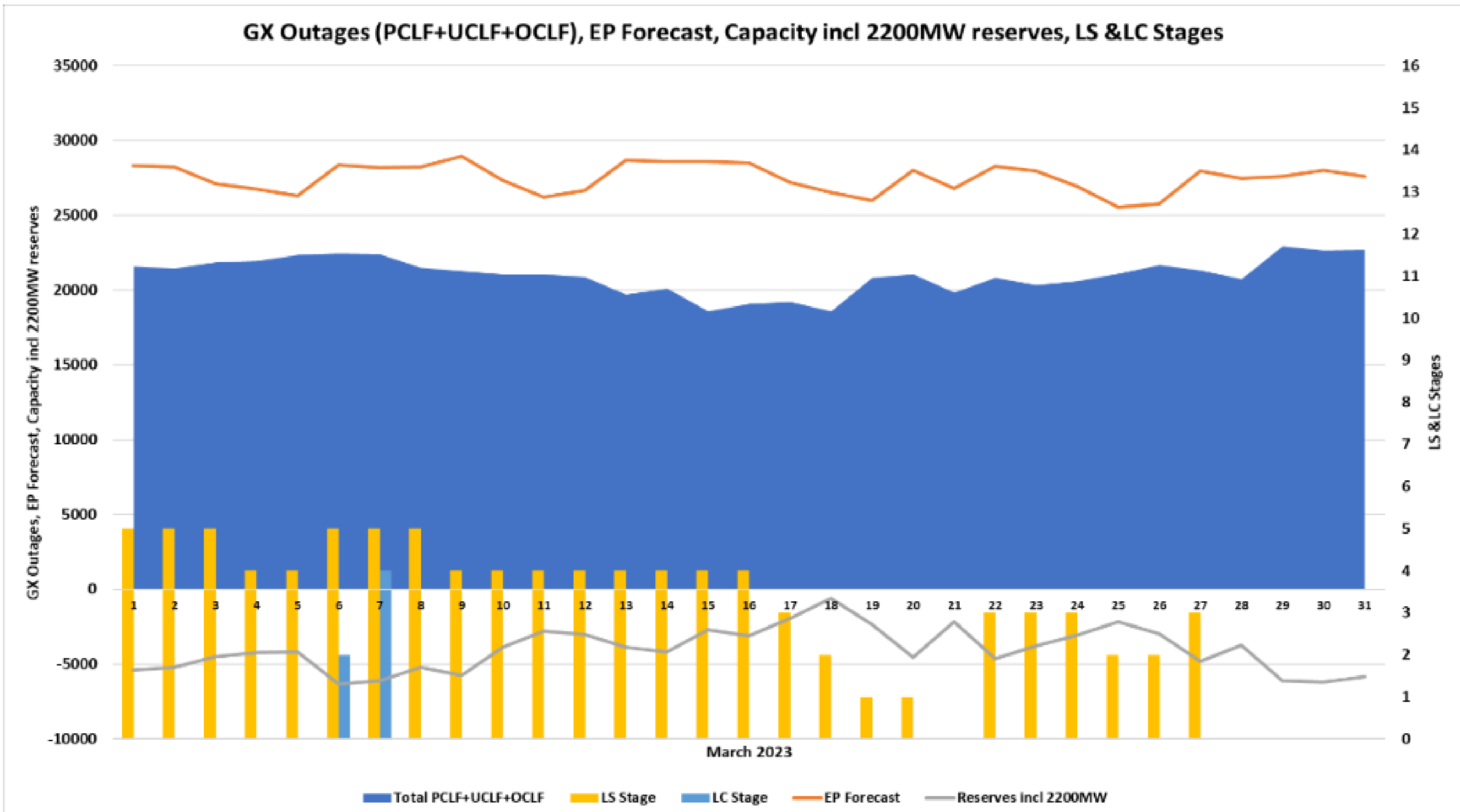
Figure 13: Total generation unavailability, forecast & reserve capacity (February 2023)



xii. March 2023

The average capacity deficit during the period 01 – 31 March was ± 3 900 MW (based on the average hourly evening forecast, including the 2200 MW operating reserve requirement) and peaked at ± 6 300 MW. Due to this shortfall in generation capacity and to conserve the compromised peaking resource levels, load shedding was implemented for the whole of March 2023.

Figure 14: Total generation unavailability, forecast & reserve capacity (March 2023)



5.2.6 Allowed revenue decision

The NERSA allowed revenue decision for FY2023 was R264 864m based on a total sales volume of 191 995GWh.

5.2.7 Sales Volume Variance Explanations

5.2.7.1 Decision vs Actual sales volumes

Table 8: Sales volume variance

Sales Volumes variance per tariff category (GWh)	Decision FY2023	Actual FY2023	RCA FY2023
Standard tariff sales including internal sales	170 485	167 086	(3 399)
NPA sales	9 528	10 307	779
Total local sales	**180 013**	**177 392**	**(2 621)**
Add: International sales	11 982	11 357	(625)
Total sales to all customers	**191 995**	**188 749**	**(3 246)**

Total local sales were 2 621 GWh lower than the FY2023 NERSA determined. This is mainly due to the actual standard tariff sales being 3 399 GWh lower than the determination. This means Eskom sold less sales volumes than the determination for standard tariffs. In addition, Eskom sold 779 GWh more than the determination for NPA sales. International sales were 625 GWh lower than the NERSA determination. This resulted in an overall variance of 3 246 GWh for the financial year with Eskom's standard tariff sales and international sales lower than the determination.

Table 9: Sales variances per customer category (GWh)

Customer Category (GWh)	Decision FY2023	Actual FY2023	RCA FY2023
Agriculture	5 856	4 785	(1 071)
Bulk / Distributors	79 305	79 480	175
Commercial	10 246	9 376	(870)
Industrial	42 326	44 635	2 310
Dx international sales*	97	80	(17)
Mining	28 118	27 843	(276)
Residential	3 225	2 625	(600)
Traction	2 245	1 668	(577)
Prepayment	7 781	6 342	(1 438)
Internal Sales	-	-	-
Public lights	202	209	7
External Sales	**179 401**	**177 044**	**(2 357)**
Internal sales	612	348	(264)
Total local sales	**180 013**	**177 392**	**(2 621)**
International Sales	**11 982**	**11 357**	**(625)**
SAE	11 982	11 357	(625)
Total sales to all customers	**191 995**	**188 749**	**(3 246)**

*Note: * Dx International sales are included in International Sales in the AFS*

Re-distributors and Industrial sectors had a positive variance while the rest of the categories had a negative variance. The main contributing sectors to the negative variance are the agriculture and prepayment sectors.

Agriculture had the highest negative variance, Eskom sold 1 071 GWh less than the decision. This category is an energy-intensive industry and is adversely affected by load-shedding due to its heavy reliance on electricity for irrigation and refrigeration. Some Operating Units noted Small Scale Embedded Generators (SSEG) customers contributing to the decline in sales which is expected to increase as the number of SSEG applications are received.

Re-distributors also had a positive variance of 175 GWh. Although this sector is heavily impacted by load shedding, higher commodity prices led to higher sales. This is mainly due to some industrial customers that are supplied by Re-distributors. The positive variance would have been significantly higher, but this was negated by load shedding and City Power increasing reliance on Kelvin power station.

Prepayment had a negative variance of 1 438GWh, this sector is heavily impacted by load shedding. The other contributing factor is moving customers from conventional meters to prepaid.

The Industrial category had a positive variance of 2 310 GWh from the decision. The Ferrochrome sector was the major contributor to the higher sales driven by higher commodity prices. Customers opted to run furnaces for longer and/or switch on furnaces that had previously been shut off. In some instances, customers did not switch off furnaces in line with their annual shutdown schedules. In addition to the higher commodity prices, other customers such as Sasol and Sappi Saiccor Mill experienced their own generation failures, which resulted in them increasing off-take from Eskom. Despite the load-shedding impacts in this sector, sales were higher than the determination.

The Commercial category had a negative variance of 870 GWh. There was less utilisation in this category, with load shedding being one of the main reasons.

The Mining category had a negative variance of 276 GWh. The platinum group sector was mostly favourable in FY2023, however, other sectors had negative variances. This was driven both by the impact of load shedding as well as the price of minerals.

The negative variances in other categories were due to the severe load-shedding, poor economy, and in some instances, severe floods.

International sales decreased because of load curtailment implemented on firm power supply agreements, suspension of non-firm supply agreements, improved self-generation among neighbouring countries and trading in the Southern African Power Pool. Sales were further affected by improved performance of some customers' own generation as well as others purchasing more of their required power from SAPP markets at rates lower than Eskom's.

5.2.7.2 International sales variances

International sales volumes were lower than the NERSA determination. The details are outlined in the table below.

Table 10: International Sales Volumes

International Sales (GWh)	Decision FY2023	Actuals FY2023	Variance
Botswana (BPC)	1 051	370	(681)
Lesotho (LEC) *	181	336	155
Mozambique			-

International Sales (GWh)	Decision FY2023	Actuals FY2023	Variance
- EDM	12	61	49
- Motraco	8 280	8 166	(114)
Namibia			-
- Nampower	613	497	(116)
- Skorpion	-	-	-
- Orange River Cross-border supply (ORC)	141	126	(15)
Eswatini (EEC)	677	609	(68)
Zambia			-
- ZESCO	-	25	25
- Copperbelt Energy Corporation (CEC)	307	-	(307)
ZESA	438	1 152	714
Short-term energy market	48	15	(33)
Nersa adjustment	234		(234)
Total Eskom International Sales	**11 982**	**11 357**	**(625)**

*Note: * Excludes standard tariff sales to Lesotho (Dx International)*

Energy sold internationally was lower than the NERSA determination. This is predominantly due to the following:

- Botswana Power Company (BPC) – Sales variance due mainly to increased rainfall facilitating more generation in Botswana.
- Electricidade de Mozambique (EDM): Sales to EDM were higher than the NERSA determination due to the nature of the agreement, which allows for flexibility in a non-firm contract.
- Motraco – Lower sales due to the interpretability allowed for in the contract.
- NamPower: Lower sales due to good rainfalls allowing for improved self-generation, and bilateral agreement with ZESCO.
- Orange River Cross-border supply (ORC) – lower sales due to impact of proportional loadshedding reduction.
- Eswatini Electricity Company (EEC): Sales to EEC were lower than the NERSA determination. This was due to EEC purchasing more energy from SAPP markets and EDM.
- Copperbelt Energy Corporation (CEC) – Sales did not materialise due to absence of wheeling path impacted sales.
- Zimbabwe Electricity Supply Authority (ZESA) – Increased sales due to a renewed contract from 50MW to 100MW.

5.2.8 Approach to revenue variance related to changes in sales volume

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

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

The NERSA MYPD3 RCA for FY2014 decision supports that Eskom is required to recover the allowed revenue as reflected in the MYPD3 decision. However, these revenues are only fully recovered if all the sales are achieved as assumed in the decision. **Therefore, in the event of lower sales materialising, it results in Eskom not recovering the allowed revenue assumed by NERSA.**

Eskom's allowed revenue in terms of the MYPD Methodology covers variable and fixed costs. The revenue decision is to cover variable costs and fixed costs. For the RCA adjustment of revenue – the methodology requires the adjustment of the **total** revenue. The variable portion is then addressed in each of the variable elements.

Fixed costs: Eskom would still need to continue to incur these fixed costs, when the sales volume increases or decreases. Fixed costs include interest and debt repayments which are represented by the return on assets and depreciation in the building blocks of the allowed revenue for regulatory purposes.

Variable costs: As sales volumes increase or decrease, there would be a concomitant increase or decrease in variable costs. The key variable costs for the electricity industry are related to primary energy costs and certain operating and maintenance costs. Primary energy, certain operating and maintenance cost variances due to lower sales are reduced in each of the primary energy and operating cost elements in the RCA balance computation.

The MYPD methodology is robust to deal with sales volume variances that may be higher or lower than that determined in the decision. If the sales volume was higher, then the revenue variance will be for the benefit of the consumer. It is correct to ensure that **the total revenue** variance (related to fixed and variable costs) is for the benefit of the consumer. There will also be additional costs related to variable elements (mainly primary energy and certain operating costs) that will be included in the RCA balance. Thus, it would be unfair to the consumer, if only the fixed cost elements are included in the RCA balance. This would mean that the consumer is impacted twice for the variable cost elements.

The same applies when the sales volume is lower than that determined in the decision. Thus, it is necessary for **the total revenue variance** to be included for the benefit of Eskom. The lower volume related primary energy and operating costs will be for the benefit of the consumer. This avoids Eskom being impacted twice for the same variable costs.

It is also submitted that when Eskom does not recover fixed costs related to lower sales volume occurring, it is in essence a temporary allowance is provided to all consumers initially. The recovery of these fixed costs occurs at a later stage, when the RCA balance is implemented.

The MYPD methodology elegantly provides for adjustment of the total revenue variance – where the volume related variable costs will be addressed with each of the variable items. In its recent FY2021 RCA balance decision, NERSA has still not applied its methodology. An adjustment was made for just the coal costs variance. This approach is still incorrect. It is not necessary for NERSA to make estimates on variable costs and then try to backfit. The requirement of the methodology is to look just at total revenue variance. Subsequent natural adjustments on all variable costs will be made when NERSA considers cost variances.

6 Factors which influence Production plan changes

From the time of the original application made in June 2021 to the time of the NERSA decision in February 2022, the energy to be secured from IPPs was significantly less than what was assumed. This has resulted in concomitant increases in energy to be secured from Eskom power stations.

For FY2023, the initial amount of energy to be sourced from IPPs, as determined by the Government Departments in 2021, was approximately 36TWh. This was then dropped to approximately 25 TWh in 2022 by Government Departments once it was realised that certain IPP programmes would not materalise. To accommodate this drop, significant adjustments to Eskom's OCGT and coal plant were made. Thus, the lack of sufficient generating capacity in the country is a root cause of the production plan not being able to meet the country demand.

For increased dependence on Eskom coal fired power stations, a production plan with a significant increase in energy utilization factor (EUF) was assumed and implemented. The dependence on Eskom OCGT plans was increased to approximately 1.4TWh. The direct impact of the increased EUF is that increased pressure is put onto the Eskom coal fired power stations to meet the demand. This implies that the power stations will have to perform beyond their optimal capacities. It has been determined that the Eskom generation fleet was operating at exceptionally high level, between 85 and 95%, utilisation (EUF). Higher utilisation leads to additional stress on components and thus to increased breakdowns – usually after a delay. This is illustrated by the fact that in 2008 (and up to 2012) the Eskom generation fleet was operating at performance levels (both for EAF as well as EUF) in line with or exceeding the benchmark performance levels of the European-based VGB association of electricity plant operators representing many hundreds of generating units – yet there was frequent loadshedding from 2008 onwards. Clearly it was not due to poor plant performance.

In February 2022, when NERSA made its revenue determination a further approximately 5TWh of energy could not be sourced from IPPs due to programmes not materialising. A decision was made to further increase energy to be sourced from coal fired power stations. This is just a high-level further adjustment made by NERSA without a supporting production plan. No details on the procurement of further coal, the capacity availability, space for maintenance, the level of performance criteria, were made available.

Table 11: Electricity Output (GWh)

Electricity Output (GWh)	FY2023			
	Revised Application	Nersa Revised Production Plan	Actual Production Plan	Actual Minus Nersa
Power sent out by Eskom stations	190 705	195 142	191 307	-3 835
Coal-fired stations (Incl. pre-commissioning)	172 683	177 853	171 131	-6 722
Virtual power stations	0	0	0	0
Hydroelectric stations	970	970	3 060	2 090
Pumped storage stations	4 707	4 707	4 081	-626
Gas turbine stations	1 466	733	3 018	2 285
Wind energy	312	312	214	-98
Nuclear power station	10 567	10 567	9 803	-764
IPP purchases	25 135	19 966	17 957	-2 009
Whelling	2 088	2 088	2 904	816
Buy-en-route	0	0	1 148	1 148
Energy import from SADC countries	8 457	8 457	7 506	-951
Total Gross Production	**226 385**	**225 653**	**220 822**	**-4 831**
Less: Pumping	6 143	6 143	5 504	-639
Total Net Production	**220 242**	**219 510**	**215 318**	**-4 192**
Dx purchases			3.11	
			215 321	

a) Comparisons

For the purposes of messaging a high-level comparison is made. It is known that such a high-level comparison is not simple as it is made out to be. Energy cannot be easily compared holistically, due to the nature of meeting demand at different timeframes and periods.

b) Energy from Eskom Coal fired power stations

For the June 2021 revenue application, the assumption was that these power stations would provide 169 217 GWh of energy. Due to the unavailability of energy from IPPs, and to enable the balancing of the production plan, Eskom was required to increase the energy from coal fired power stations to 172 683GWh (Jan 2022). This was achieved by increasing the EUF. In its decision (Feb 2022), NERSA increased this energy requirement to 177 853GWh. This is to meet the shortfall in the IPP energy. A revised production plan was not developed. Thus, the details of the actual power station allocations are unknown. It seems that this was a high-level adjustment made by NERSA. The actuals turned out to be very similar to what was assumed in Eskom's updated assumptions. A difference of 1 552 GWh was experienced. It should be noted that this was higher than the original application made by Eskom. A variance of 6 772GWh was noted when comparing the actual to the NERSA decision. This is understandable since the basis of the NERSA decision is not clear. Eskom exceeded the energy from coal fired power plants originally assumed and achieved over 99.9% of the updated production plan.

c) Energy from IPPs

The DMRE, DPE and National Treasury provide clarification of the IPPs to be included in a revenue application. Eskom is not in a position to review these proposals. The original decision by the Government Departments proposed that approximately 35TWh of energy will be secured from IPPs (June 2021). By January 2022, the total energy from IPPs would be 25TWh. When NERSA made its decision, it made an assessment and determined that approximately 20TWh would be secured from IPPs. This is logical, since it was evident that certain projects would not materialise. However, the automatic assumption that Eskom, mainly through its coal fired power plants will be in a position to absorb the shortfall did not materailise. The actual from IPP generation turned out to be even further lower, by about 18TWh. Thus, the difference from the originally anticipated IPP energy was almost 50%.

d) Energy from Eskom OCGTs

The utilisation of Eskom OCGTs were originally 211 GWh for FY2023 (June 2021). An update due to reasons provided above, showed that a revision to 1 466GWh was necessary. NERSA's decision was half of this. The actual, utilised in terms of the MYPD methodology, was a little over 3TWh.

e) Observations

Enormous pressure has been put on Eskom coal fired power stations to meet the demand during FY2023. It should be noted that load shedding to the extent of approximately 13 TWh was experienced. A significant shortfall in the assumptions made on IPPs was also experienced. This resulted in major challenges in trying to address load shedding in a bid to minimise load shedding. Both Eskom and IPP OCGT's contributed to minimise the load shedding.

7 Primary energy

7.1 Primary energy variances and RCA impact for FY2023

Total primary energy in the FY2023 revenue decision was R138 061m. Eskom incurred primary energy costs of R157 066m in the year which resulted in a variance of R19 005m. An adjustment of R12m was made to coal burn which comprises the reversal of the coal obligation provision and the alpha risk adjustment. The adjustment increases the total primary energy variance to R19 016m for the benefit of Eskom. Refer table below for the RCA variance for total primary energy.

Table 12: Total primary energy comparison and RCA impact

Primary Energy (R'm)	Decision FY2023	Actual FY2023	Variance	RCA Adjustment	RCA
Coal usage	65 151	63 069	(2 082)	12	(2 070)
Water usage	3 138	2 332	(806)	-	(806)
Fuel procurement service	288	274	(14)	-	(14)
Coal handling	2 408	2 293	(115)	-	(115)
Water treatment	610	669	59	-	59
Sorbent usage & Handling	279	192	(87)	-	(87)
Gas and oil (coal fired start-up)	3 686	8 807	5 121	-	5 121
Nuclear	751	674	(77)	-	(77)
Coal and gas (Gas-fired)	10	7	(3)	-	(3)
OCGT fuel cost	3 753	21 355	17 602	-	17 602
Demand Response (DR)	381	298	(83)	-	(83)
Demand Response - power alert	40	59	19	0	19
International Purchases (Dx)	-	12	12	-	12
Other	1	(2)	(3)	-	(3)
Primary Energy	**80 496**	**100 040**	**19 544**	**12**	**19 556**
Independent Power Producers (IPPs)	**43 130**	**43 534**	404	-	404
International Purchases (SAE)	4 589	6 459	1 870	-	1 870
Environmental levy	7 132	7 033	(99)	-	(99)
Carbon tax	2 714	-	(2 714)	-	(2 714)
Total primary energy	**138 061**	**157 066**	**19 005**	**12**	**19 016**

As is reflected in the table above, the key variances are due to the OCGT fuel costs, coal usage costs, costs related to gas and fuel- oil for the start-up of coal fired power stations. Some of these variances are in favour of Eskom and some in favour of consumers.

AFS Extract, March 2023 reflects the actual total primary costs of R154 942m below:

	Note	Group 2023 Rm	Group Restated 2022 Rm	Company 2023 Rm	Company Restated 2022 Rm
33. Primary energy					
Own generation costs		106 706	92 414	106 706	92 414
International electricity purchases		6 471	5 316	6 471	5 316
Independent power producers		41 765	35 203	41 765	35 203
		154 942	132 933	154 942	132 933

Generation costs relate to the cost of coal (including logistics), uranium, water and liquid fuels that are used in the generation of electricity. Eskom uses a combination of short-, medium- and long-term agreements with suppliers for coal purchases and long-term agreements with the Department of Water Affairs to reimburse the department for the cost incurred in supplying water to Eskom.

Table 13: Primary energy reconciliation to AFS

Primary energy reconciliation to AFS (R'm)	Actuals FY2023	Note
Primary energy per AFS	154 942	
Add: IFRIC 4 IPP capacity payment	1 635	1
Add: IFRIC 4 IPP capacity payment accrual	133	1
Add: Demand response	298	2
Add: Power Alert	59	2
Other	(2)	
Actual primary energy for RCA	**157 066**	

Note:

1 *In terms of IFRS (IFRIC 4), capacity payments in relation to Avon and Dedisa are not accounted for as part of IPP costs in the income statement of the AFS. For regulatory purposes, this capacity payment is accounted for as an IPP purchase cost.*

2 *Demand response/Power alert – an adjustment is required to allow for like-for-like comparison. In the actuals these costs are reflected in revenue. The reallocation from revenue to primary energy is required to enable comparison to the NERSA decision.*

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

8 Coal Burn Costs

8.1 Mandate and background

Eskom's mandate is to safely and sustainably identify, develop, source, procure and deliver the necessary amounts of coal of the required quality for Eskom's power stations, at the right time and at optimal cost. In June 2021, Eskom submitted a revenue application for MYPD5 (FY2023 – FY2025). The assumptions that informed the application, and the corresponding reality, are stated in the assumption's tables in the relevant sections.

8.2 FY2023 Reasons for decision

NERSA's reasons for decision stated that:

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

Table 14: Coal burn costs per contract type NERSA decision

Coal Burn: FY2023 Revenue Decision (R'm)	Cost Plus	Fixed Price	Medium term	Total
NERSA Decision burn cost (R'm)	19 918	16 708	28 525	65 151

8.3 Assumptions

The FY2023 revenue application was based on certain assumptions. During the year, some of these assumptions were realised while others were not. The differences in assumptions and the explanations are provided in each part of the document.

Table 15: Assumptions

Application FY2023	Actuals FY2023
Electricity production from coal fired plant would be 172 683 GWh.	Electricity production from coal fired plant was 171 131 GWh, including pre-commissioning burn of 813 GWh.
Cost Plus produce at expected levels, which are below contractual volumes	With the exception of Kriel and New Vaal mines, Cost Plus mines produced below expected levels.
Fixed Price mines produce at contractual levels, except for MMS which produces below contractual volumes.	MMS produced below expected volumes. Both Kusile and Medupi Power Station generation was lower than expected.
Kriel and Matla CSA's will be extended	The Kriel CSA has been extended. Negotiations to extend the Matla CSA are underway.

8.4 Total coal costs for FY2023

The table below compares the coal costs in the MYPD5 revenue decision for FY2023, to the actual coal burn expenditure for FY2023. The variance explanations that follow for each category of expenditure are for the difference between the application and the actual expenditure.

Table 16: Total coal burn costs (R'm)

Coal Burn (R'm)	Decision FY2023	Actuals FY2023	Variance
Cost Plus	19 918	19 585	(333)
Fixed Price	16 708	17 103	395
Medium Term	28 525	26 381	(2 144)
Total Coal Burn Cost	**65 151**	**63 069**	**(2 082)**

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

8.4.1 NERSA MYPD methodology requirements

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

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

Eskom has always made its RCA applications in terms of the methodology. In the court judgement related to the FY2015 to FY2017 RCA decisions, the finding was that it was not correct for NERSA to further disallow costs for coal when, in the course of applying the methodology, Eskom had already accounted for these costs in the RCA.

8.4.2 Implementation of MYPD methodology

Applying the formula in the MYPD methodology, the variances per contract type are illustrated in the table below.

Table 17: Coal burn RCA variances breakdown for FY2023

Coal burn variance breakdown	Unit	Cost Plus	Fixed Price	Medium term	Total
Coal burn price variance	R 'm	(2 615)	(329)	1 290	(1 654)
Coal burn volume variance	R 'm	2 420	742	(3 577)	(416)
Coal burn costs included in RCA	**R 'm**	**(196)**	**413**	**(2 287)**	**(2 070)**

The total burn variance is R2 070m in favour of the consumer, comprising a price variance R1 654m and a volume variance of R416m.

8.4.3 Coal burn

Coal burn is derived from opening stock being added to purchases as illustrated in table below. A coal burn cost of R68 327m was included in the revenue application. NERSA determined the coal costs to be lower at R65 151m. However, it is not clear what coal purchases costs or what coal volumes were used to arrive at the burn cost as the reasons for decision do not include coal purchase costs. Eskom, thus, compares the application to the actual purchases. Thus, motivations provided compare actuals to the application. Actual coal burn cost was R63 069m as shown in the table below.

Table 18: Coal burn derived

Coal Burn (R'm)	Decision FY2023	Actuals FY2023	Variance
Opening stock		16 117	
Purchases		61 208	
Take or pay adjustments		224	
Closing stock		(14 480)	
Commercial coal burn	**65 151**	**63 069**	**(2 082)**

The total variance between actual burn cost and what was determined is R2 082m, with the actual cost being lower than the determination. Total coal burnt was 2 588 ktons more than assumed in the application and 432 ktons less than the decision. The coal fired power stations generated 1 552 GWh (including pre-commissioning energy) less than assumed.

The analysis below is an explanation of the actual FY2023 costs versus the costs and volumes for FY2023 that were included the revenue application.

Coal burn costs and volumes are derived from coal purchases. The coal purchases as per the revenue application are compared to the actual FY2023 coal purchases to explain the difference in the burn costs and volumes. Total coal purchases volumes were 4 232 ktons less than assumed in the Eskom application. The lower volumes were due mainly to lower sales. Purchases were lower on the Short- and Medium-Term contract types.

The average price Eskom pays for coal is determined by the volume of coal procured from each type of contract and the price of coal from each type of contract. The R/ton coal price was 11% lower than the application on average. The R/ton was R76 (11%) lower. This is a result of the mix of coal purchases between the contract types.

The R/ton cost from the Cost-Plus contracts was 17% lower because of lower costs. Fixed Price production was 5% higher while costs were lower by 13%, resulting in the R/ton being 17% lower. The lower Fixed Price R/t was offset partially by higher prices on the Cost-Plus purchases. Volumes on the ST/MT purchases were 14% lower, with the ST/MT purchases cost also being 14% lower. The ST/MT R/t was flat.

The R/ton is impacted by various factors:

- **Cost plus contracts**

Most of the Cost-Plus mines are no longer able to produce contractual volumes. Recent capital underinvestment in the mines together with historic over supply and the age of the mines has made underproduction the norm in the recent past. The mines attempt to supply expected volumes. However, it is not possible for the mine to supply contractual volumes without having invested in sufficient capital expenditure. When more detailed requirements are known, discussions are held with the mine. Eskom and the mine will agree on the volume to be produced. The age of the mines and historical supply profiles compound the production challenges. In FY2023 application, Eskom assumed production levels lower than contractual volumes because of these factors and because of the delay in investment in the mines.

The unit price (R/ton) of coal from the Cost-Plus mines is the total cost of operating that mine for that period divided by the production volumes. The export price has little direct impact. During FY2023 the volumes from Cost Plus mines was almost on par with what was expected. The Cost-Plus mines provided approximately 34% of the coal procured in FY2023 against the assumption in the application of 32%.

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

Coal procured from the Cost-Plus contracts was 62 ktons higher than in the application. Total spend was R3 744m lower than in the application and the R/ton was R114/ton lower.

- **Long term fixed price contracts:**

This category comprises the MMS (Duvha), Matimba (Grootegeluk) and Medupi (Grootegeluk) contracts. The price is determined by the terms of the contract, e.g., an annual escalation is applied to the price established at the inception of the contract. The contract will stipulate how the escalation is to be calculated. None of the existing contracts are impacted directly by the price of export coal. Approximately 30% of coal for FY2023 was sourced from long term fixed price contracts against an assumption in the Eskom application of 28%.

The total average R/ton cost for fixed price coal was lower than the application. Coal for Medupi and Matimba came in at lower than assumed R/ton costs.

The volume of coal was 1 505 ktons more than assumed in the application. Total spend on the long term fixed price mines was R2 682m less than the application. The average R/ton was R123/ton lower.

- **Short Term/ Medium Term (ST/MT) contracts:**

These contracts are of varying durations. They are essentially fixed price contracts but are differentiated from the original long-term fixed price (40-year) contracts referred to above because they are much shorter in duration. NERSA differentiates further by separately identifying contracts less than three years in duration as short term and those longer than three years as medium term. Eskom does not make this distinction for internal purposes but has done so for purposes of the RCA calculations as per the methodology. Apart from the duration, both these contract types have similar terms and conditions. The suppliers supply contractual volumes. As with the long-term fixed price contracts, the price is determined by the terms of the contract, e.g., an annual escalation is applied to the price established at the inception of the contract. The contract will stipulate how the escalation is to be calculated. The export price may have an impact in that the supplier may reference this price at the time of negotiation. However, Eskom will always negotiate a fair price within the environment at the time. Whether this price correlates to the export price at any given time is likely to be coincidental. These contracts supplied approximately 36% of the coal in FY2023 against the assumption in the application of 40%.

In FY2023, Eskom purchased 5 799 ktons less on ST/MT contracts than expected. The total spend on ST/MT purchases was R4 076m (14%) less than assumed and the R/ton was marginally lower than expected (R3/ton). This includes the cost of transporting this coal from source to the power stations.

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

Table 19: Contract Price Adjustment illustration

	Weight	B (previous index)	Base Date	L (new index)	Escl Date	(L-B)/B	Weighted Avg
Labour	0.26	16752.2	14-Apr	18 264	15-Apr	0.09	0.02
Diesel	0.15	1,329.75	14-Apr	1 171	15-May	-0.12	-0.02
Electricity	0.04	106.7	14-Apr	119	15-Apr	0.11	0
Mining Machinery	0.13	113.5	14-Apr	114	15-Apr	0	0
Overheads_ CPI	0.1	109.1	14-Apr	114	15-Apr	0.04	0
Profit & Capital Rec	0.22	109.1	14-Apr	114	15-Apr	0.04	0.01
Fixed	0.1		14-Apr		15-Apr		-
Total	1						-
Annual PAF (1 + sum)							1.02
Base Price							12.7
Adjusted Price							13.02
New price							13.02

8.4.4 Coal transport

Coal may be transported by conveyor, rail, road or a combination of modes. ST/MT coal is typically unable to be transported by conveyor. Any costs that can be recovered from the contractor are already embedded in the actual costs. The mode of transport for FY2023 is reflected in Table below.

Table 20: Coal transported (ktons)

Transport mode	Application FY2023	Decision FY2023	Actual FY2023	Difference (Actual - Application)
Conveyor	61 590	No breakdown in RfD	63 157	1 567
Rail	7 678		2 487	(5 190)
Road	33 379		32 771	(608)
Total	**102 647**		**98 415**	**(4 232)**

Conveyor is the cheapest mode of transport. The Cost Plus and Fixed Price mines, which are located close to the stations, use this mode.

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

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

8.4.5 Coal qualities

Reduction of coal related load losses (OCLF) remains a key focus. This is in response to Eskom's emphasis on plant availability in a constrained generation environment (every MW counts). Matla (78%) and Camden (12%) made up 90% of the coal-related load losses for the period. Hendrina (2%) and Majuba (8%) accounted for the remaining 10%. Generally, coal quality has improved at most power stations, which has resulted in minimum coal related OCLF at Kriel, Tutuka, Kendal, Arnot and Grootvlei.

8.4.6 Coal stock

The value of closing stock at the end of FY2023 was R14.480bn while total closing stock days were 65. Total stock levels translate to coal volumes of 29 726 ktons. If the stock at Medupi and Kusile Power Stations were excluded, stock days declined to 29 days.

9 Other Primary Energy

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

MYPD Methodology - Other Primary Energy Costs

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

9.1 Variances in water usage costs

9.1.1 FY2023 Reasons for decision

As clarified in the NERSA reasons for decision related to the FY2023: *"Thus, the rationality of the application is fairly good. The figures presented in the application for water are reasonable, however, as a result of a 3% increase in coal production usage, water volumes and costs also escalated by approximately 3% to R3 138m"*.

9.1.2 Water usage assumptions

Table 21: Water Usage Assumptions

Determination FY2023	Actual FY2023
Water consumption per unit was 1.34 litres/kWh at coal fired power stations	Water consumption per unit was 1.39 litres/kWh at coal fired power stations
Current infrastructure is old, and the backlog of maintenance will also result in an increase to the water tariff.	The DWA was unable to carry out all planned maintenance and still has a backlog due to a lack of appointment of a maintenance contractor and long lead times.
Kusile and Medupi will use water for FGD	FGD was not Implemented at Medupi in FY23.

9.1.3 Water usage costs

NERSA increased the application of R3 047m for water costs in FY2023 to R3 138m. Actual expenditure was R2 332m resulting in a variance of R806m for the benefit of consumers.

The water costs are composed of various tariffs. The table below reflects the costs per component. The analysis is done between the actual and application numbers as NERSA did not provide a breakdown in its decision.

Table 22: Components of water usage costs (R'm)

Water Costs (R'm)	Actual FY2023	Application FY2023	Decision FY2023	Variance: Actual-Application
Amortisation	(238)	-		(238)
CMA	13	16		(3)
O&M	186	295		(109)
Pumping	617	639		(22)
CUC	841	889		(48)
Water Research Levy	18	18		1
Water Resource Charge	354	301		53
VRT	489	511		(22)
Waste Discharge Charge		162		(162)
Operational Risk transfers		120		(120)
Third Party credit	(52)	-		(52)
Lab Services	3	-		3
PTM	5	-		5
Total Coal Stations	**2 236**	**2 950**		**(714)**
Nuclear and Peaking stations				
Total Generation water costs	**2 236**	**2 950**	**3 138**	**(714)**
Peaking stations	90	87		3
Renewables	0	2		(2)
Nuclear - Koeberg	5	8		(3)
Group Capital	1			1
Total Generation water costs	**2 332**	**3 047**	**3 138**	**(715)**

The price of water is impacted by the tariffs that government gazettes. Eskom assumed water related costs would increase by between 6% - 8%. In actual mode, total costs are impacted by actual legislated tariffs and the volume of water consumed.

The largest contribution to the variance is due to amortisation operations and maintenance, Waste Discharge Charge and Operational Risk Transfers. The amortisation adjustment is a result of the external auditor's request that water assets be reclassified from Future fuel to Fixed Assets.

9.1.3.1 Capital unit charge:

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

9.1.3.2 Vaal River Transfer (VRT):

This is a legislated tariff. VRT is paid on all water that is sourced from the Vaal River scheme. The Vaal Water system is also the system of last resort. Water is drawn from the Vaal to supplement the other systems. For FY2023, the actual tariff was lower than the expected.

9.1.3.3 Pumping costs:

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

9.1.3.4 Operations and Maintenance:

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

9.1.3.5 Third Party Credit:

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

9.1.4 Water volumes

The volumes of water consumed are driven primarily by the electricity produced by the power stations. The volume consumed to generate a unit of electricity varies per power station. The total consumption will depend on the mix of stations used to generate electricity, with older stations consuming more. Most of Eskom's stations are beyond the halfway mark of their lifespans. Although the coal fired stations produced less than assumed, actual water consumption per unit of electricity was higher at most stations than was assumed, resulting in a total increase in water used.

The overall water performance at coal fired power stations for FY2023 was 1.39 l/uso. The stations consumed 28 287 million litres more than expected, despite generating fewer GWh. Ageing water infrastructure and lower production at dry cooled stations – Kendal, Majuba, and Kusile Power Stations, resulted in the rate of consumption being higher.

9.2 Fuel procurement

Table 23: Fuel Procurement

Fuel Procurement (R'm)	Application FY2023	Decision FY2023	Actuals FY2023	Variance (Actual - Application)
Manpower	167	167	178	11
Consulting fees	9	9	2	(7)
Legal fees	66	66	28	(37)
Travel and subsistence	4	4	1	(3)
Other	42	42	65	23
Total	**288**	**288**	**274**	**(14)**

9.2.1 NERSA methodology requirements

The methodology applicable to FY2023, as published during 2016 stipulates more detail which is required for other Primary Energy costs. The fuel procurement costs have been included as prudent costs in recent NERSA decisions. Fuel procurement expenditure had a variance for the benefit of the consumer of R14m. The primary components of fuel procurement expenditure and the reasons for the bulk of the variances in expenditure are:

a) Employee benefit costs

Employee benefit costs comprise the bulk of the fuel procurement costs. These costs include all salaries, allowances, company contributions and legislated costs such as workman's compensation and skills development payments. Following multiple years during which financial constraints resulted in recruitment of new employees being halted, PED filled some of the critical vacancies in the department in FY2023.

b) Legal fees

Expenditure on legal fees for FY2023 was R28m against the application of R66m. The under expenditure was due to the conclusion of the Anglo – Seriti transaction.

c) Other

'Other' costs include the corporate overheads allocated to the Primary Energy Division, insurance, marketing and subscriptions to databases that are relevant for the business. The over expenditure was incurred on insurance costs, which have increased substantially.

9.3 Coal Handling costs

The NERSA MYPD4 Reasons for Decision did not apportion its decision per power station for coal handling costs. In the absence of such apportionment, the RCA motivation will be based on the prudency of actual expenditure.

Table 24: Summary of Coal Handling Costs

Coal Handling (R'm)	Application FY2023	Nersa Adjustment	Decision FY2023	Actuals FY2023	Variance
Coal handling	2 480	(72)	2 408	2 293	(115)

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

The following is a further explanation of the **main cost components** of coal handling:

a) Labour

Operational labour comprises of various types of labour ranging from skilled site / shift supervisors and managers to semi-skilled operators of the various yellow plant to unskilled general workers. It is required to operate the plant and equipment.

Maintenance labour is required for activities to keep the plant and equipment operational.

The size (coal plant footprint) and complexity (eg. number of conveyors, whether it the conveyor systems are automated of manual, etc) impacts on the employee number requirements at each station.

b) Yellow and white plant description and function:

Table 25: Yellow and white plant description and function

Item	Yellow Plant Descriptation	Job description
1.	Bull Dozer	Pushing of import coal for reclaim the coal
2.	Front end loader	Pushing up coal and load coal into the mobile feeders
3.	Dump Trucks	To move coal to various and difficult areas
4.	Motor Grader	To grade the roads on coal stock-pile and associated gravel roads
5.	Tipper Trucks	Transport ot coal to various areas where its required
6.	Smooth Drum Roller	Compact Seasonal and strategic stock-pile and gravel roads
7.	Water Tanker	Dust suppression on coal stock-piles and gravel roads
8.	Tractor Loader Bucket/LTB	Clean sumps and dig trenches
9.	Excavator	To lead tipper and dump trucks. To break strategic piles loose
Item	**White Plant Description**	**Job desciption**
1.	LDV's	Transport spares and tools
2.	7,12&23 seaters	Transport employees on-site and Home-work-home

Dozers are additionally used for building of Live and Seasonal Piles, Reclaiming coal from Strategic Stockpiles

Dump trucks are moved to relocate coal to various stockpiles or feeding points depending on the coal movement strategy. ADT's (Articulated Dump Trucks) are also used on several sites due to their larger payload abilities.

Motor Graders are extensively used for the spreading and profiling of coal on the various stockpiles.

Excavators should not be used for loading trucks and breaking strategic stockpiles (rather dozers). They are used when the correct machines are not available.

9.3.1 The Drivers of Coal Handling costs

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

9.3.1.1 Coal supply constraints

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

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

- When there is a trip at the power station (production stops) or feeding conveyors are not available, delivered coal needs to be re-directed to the stockpile, to be reclaimed at a later stage. The reduced performance at stations in terms of unavailability (UCLF) / trips has, therefore, a direct consequence in terms of increased coal handling costs.
- When there are mine delivery problems, coal needs to be reclaimed from the stockyard / stockpiles by means of mechanised stacker/reclaimers, drum reclaimers or mobile feeders for the units / boiler. For Kusile stockyard startup conditions, the normal operation is to stack coal on the stockyard and reclaim with mechanised equipment for the purpose of homogenization to supply the boiler with consistent coal quality.
- When a mine supply conveyor breaks, additional handling via bulldozer and or front-end loaders (yellow plant) would be required to manually feed coal into chutes or mobile feeders feeding onto conveyers (for the units / boiler). The cost of conveyor repairs would also be allocated to coal handling.
- Although most power stations do have dedicated mines, these mines sometimes undersupply coal for various reasons ranging from being unable to mine at maximum capacity, moving between coal seams/deposits and/or reaching their end of life. Therefore, mine conveyed coal needs to be supplemented with road delivered coal, which incurs significant handling costs.

9.3.1.2 The Contract Type

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

9.3.1.3 Conveyor spills

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

9.3.1.4 Type of Coal transport

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

9.3.1.5 Weather conditions

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

9.3.2 Conclusion on Coal Handling

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

9.4 Water treatment costs

Table 26: Summary of water treatment costs

Water treatment (R'm)	Decision FY2023	Actuals FY2023	RCA FY2023
Water treatment	610	669	59

9.4.1 Description of Water Treatment Processes

9.4.1.1 Demineralised Water Production

Raw water is treated in a pretreatment plant, which comprises clarifiers and filtration systems, to produce filtered water and potable water. In the pretreatment process, various pretreatment chemicals are used, including coagulants, flocculants, and disinfectants.

Filtered water is then further treated in the demineralised water production plant. At most stations, ion exchange processes are used, whereas at a few stations, membrane processes are used to produce demineralised water.

The ion exchange processes use ion exchange resin beads, loaded in vessels, to remove ions from the water, thereby demineralising the water. These resin beads have a certain ion exchange capacity and become “exhausted” after a certain run length. The demineralised water production vessels are therefore periodically taken out of service, in order to regenerate the resin, and restore the ion exchange capacity. This resin is regenerated using chemicals such as sulphuric acid and caustic soda. These constitute the bulk of the demineralised water production cost. The quantity of chemicals used is mainly dependent on the demineralised water production rate and the run length of the ion exchange resins. The latter is influenced by the feed water quality, the condition of the ion exchange resins, and the efficiency of the regeneration process.

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

The unavailability of locally manufactured caustic soda during some months of the year, due to failures at the supplier’s manufacturing plant, resulted in some of the caustic soda used at the stations having to be imported. This increased the cost of demineralized water production and condensate polishing. The impact on the station’s water treatment expenditure was dependent on how many caustic soda deliveries were required during those months, which in turn was dependent on the caustic tank levels at the time and the station’s caustic soda usage rate. A back-up supply contract is in the process of being established.

9.4.1.1.1 FACTORS WHICH CONTRIBUTE TO INCREASED CHEMICAL USAGE ARE AS FOLLOWS:

- **Change in raw water quality**: The design of the demineralised water production process is based on a specific raw water quality. A deterioration in the raw water quality compromises the efficiency of the demineralised water production process and results in more frequent regenerations, additional cleaning measures having to be implemented and a higher chemical cost. Some of the stations have experienced a deterioration in the quality of the raw water and/or quality of the feed water.

- **Deterioration in the availability, reliability and efficiency of the demineralised water production plant**: Generation has been experiencing a decrease in the reliability and performance of a number of demineralised water production plants. This has resulted in more chemicals being used and has increased the cost of treatment. The refurbishment of the demineralised water production plants has been identified as a priority focus area. Refurbishment plans have been developed for each station and are being tracked.

- **Increase in demineralised water consumption**: There has been a significant increase in the demineralised water consumption of generating Units over the last few years, including in the last financial year, over and above the projected targets. This has required an increase in the demineralised water production rate, to try to keep up with demand. In some cases, the demineralised water consumption is between 2 and 5 times the station's design demineralised water consumption. This has resulted in an increase in the cost of demineralised water production. The main contributors to high and increasing demineralised water consumption, and demineralised water losses, across the fleet were the high number of Unit trips, the high demineralised consumption during the return to service of Units, and the high number of defects on the Units. The stations have developed comprehensive action plans, which list all the contributors, estimate the contribution of each contributor, identify root causes, provide actions to address the root causes, and track execution readiness.

9.4.1.2 Potable Water Production

Filtered water is also further treated to produce potable water.

Potable water is used for drinking purposes at the power station, and is also sent to adjacent township, mines or other third parties. In the power station, it is also used in various other processes, including fire protection.

One of the factors that contributes to the cost of potable water production is the rate of consumption of potable water by the different users.

9.4.1.3 Condensate Polishing

Some of the power stations use condensate polishing on the Units to control the chemistry of the water and steam within the boiler-turbine circuit.

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

9.4.1.4 Cooling Water Treatment

Most power stations require water for condensing the exhaust steam from the final turbine system. This allows the water within the boiler-turbine circuit to be reused by the condensed steam being fed back as boiler feedwater.

The condensing of the steam occurs in a heat exchanger called the condenser. Systems that utilise air as the cooling medium are referred to as dry cooling systems. Systems where water is used as the cooling medium in the condenser are referred to as a wet cooling systems. These wet cooling systems are commonly known as main cooling water systems. The table below indicates which stations have dry cooling systems and which have wet cooling systems or main cooling water systems.

Table 27: Main Cooling Technologies Implemented per Power Station

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

All power stations also operate an auxiliary cooling system which is used to address the cooling requirements of equipment/systems supporting the main power generation, for example boiler/turbine pump cooling, oil coolers, bearing cooling, etc.

Wet cooling systems (main and auxiliary) require chemical treatment to prevent scaling and corrosion in the cooling systems.

Main cooling water systems are treated by means of clarification, lime treatment, desalination and/or acid treatment. The type of treatment used at the station impacts the water treatment expenditure of the station. Clarification and lime treatment comprises a significant portion due to the significant volume of chemicals dosed. Desalination is only applied for the treatment of cooling water at Tutuka, Lethabo, Grootvlei and Komati. Desalination has the highest treatment cost due to the number of chemicals used. The treatment with the lowest cost is acid treatment, where sulphuric acid is added directly into the cooling tower ponds. This treatment is applied when clarification and lime treatment is not installed or is not available.

The warm cooling water is an ideal environment for microbiological growth which when formed on the heat exchanger surfaces, negatively affects the efficient transfer of heat across the media. Biocides, antiscalants and dispersants are chemicals that are routinely dosed into the wet cooling systems to reduce the microbiological activity in the system.

Treatment for auxiliary cooling systems involves the dosing of chemicals to prevent microbiological growth, scale formation and corrosion.

This year, the cost for main cooling water treatment was lower than planned at most stations because of a deterioration in the availability, reliability and efficiency of the cooling water treatment plants (clarifiers, lime systems, desalination plants, etc.). This is being addressed through the implementation of maintenance strategies at the stations. The cost of cooling water is expected to increase back to normal as the availability, reliability and efficiency of the cooling water treatment plants is restored.

The leaks in the auxiliary cooling systems resulted in increased chemical dosage at most sites, which increased the cost of auxiliary cooling water treatment. The causes of leaks have been identified and are being addressed.

9.4.1.5 Ash Water Treatment

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

In a dry ashing system, the ash is transferred from the boilers to the ash disposal site on conveyor belts. This system requires no water treatment.

In a wet ashing system, the ash from the boiler is mixed with water until it forms a slurry and then pumped to the ash dam. The ash settles in the dam and the water is returned to the station ash system to be reused for ash slurrying. The chemical properties of the water from the ash dam are such that they cause scale formation in the pipeline. To combat this, chemicals are dosed into the ash water return pipelines. Stations that operate wet ashing systems include Arnot, Camden, Duvha, Grootvlei, Hendrina, Komati, Kriel and Matla.

9.4.1.6 Sewage Treatment

The stations are located in remote areas, a significant distance from municipalities. Therefore, all sites were designed with a sewage treatment plant to treat the sewage from the station ablution facilities, washrooms and kitchens.

At sites that have a township that accommodates Eskom employees and their families, a separate sewage treatment plant is installed to receive and treat the sewage from the township residents / facilities.

Most power stations have contracts in place to outsource the operation and maintenance of these plants.

9.5 Sorbent Usage and Handling variance

Table 28: Sorbent usage & handling variance

Sorbent Usage & Handling	Decision FY2023	Revenue Application	Actual FY2023	Decision vs Actual
Kusile (R'm)	277	277	192	86
Kusile (ktons)	280	280	201	79

Note: Sorbent usage amounts to R186.5m and Sorbent handling amounts to R5.8m

9.5.1 FY2023 Reasons for decision

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

9.5.2 Sorbent usage variance

The utilisation of sorbent is related to the quantum of energy produced at Kusile Power Station. Due to the variance in the energy, the sorbent utilisation was lower than originally envisaged.

9.6 Start-up gas and oil costs

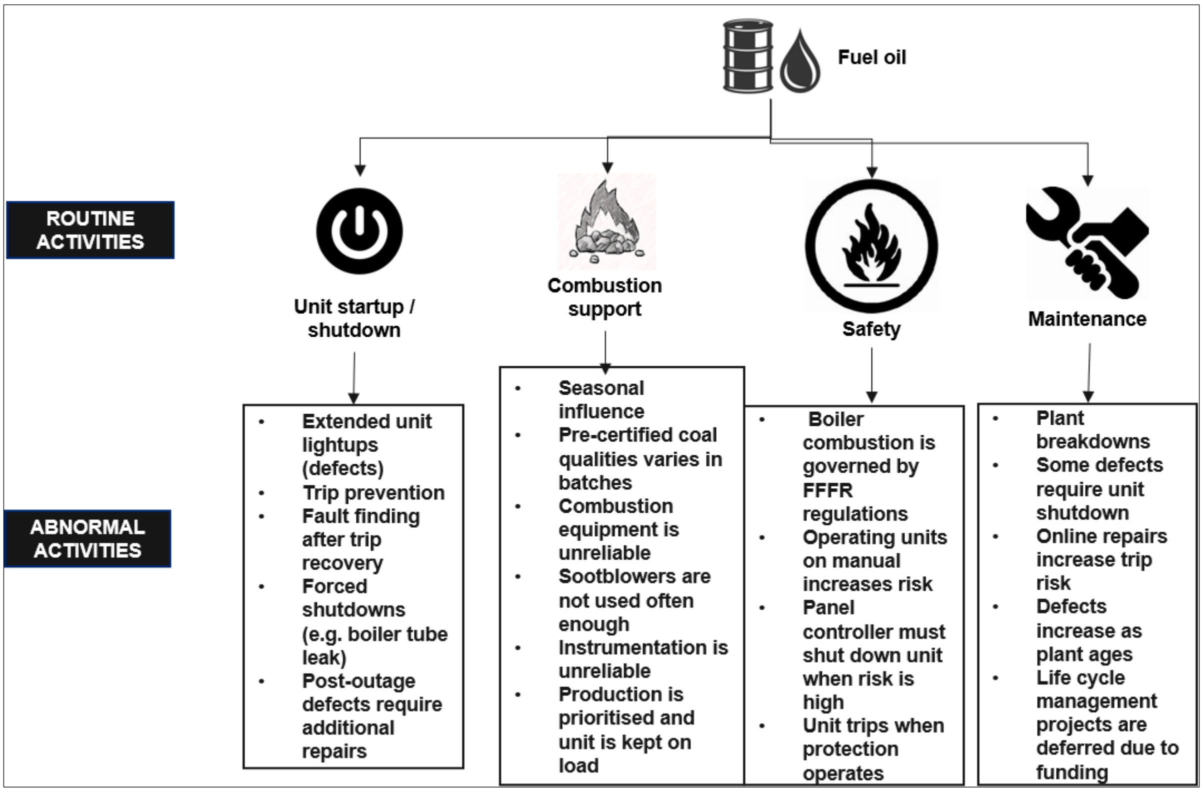
The NERSA FY2023 RfD did not apportion its decision per power station, hence the RCA motivation is based on the actual expenditure.

Table 29: Summary of start-up gas and oil costs

Start-up Gas & Oil (R'm)	NERSA Decision	Actuals FY2023	RCA FY2023
Start-up gas & oil	3 686	8 807	5 121

9.6.1 Main drivers of Fuel-oil Usage

Figure 15: Routine fuel oil usage categories



9.6.1.1 Routine fuel oil usage categories are summarised below.

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

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

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

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

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

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

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

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

b. **Trip prevention** – risk mitigation is required when units operate with known risks such as boiler tube leaks or reduced coal qualities and need to run the unit long enough to be able to resolve the risk outside of the peak demand periods.

c. There are occasions when the unit trip protection operates and results in a **forced shutdown** (e.g. boiler tube leak). The unit is designed to trip when a protection capability operates to ensure that costly catastrophic damage to the boiler, turbine or generator is avoided or minimised.

d. **Post-outage defects** arises if the repair was scoped incorrectly, or the quality of the repair was inadequate. The use of fuel oil arises when the repair is either performed with the unit still in service or it might need to be shut down and repaired offline.

ii. **Combustion support**

a. Seasonal influences can impact the amount of fuel burnt because heavy rainfall can cause coal blockages at transfer points or cause conveyor belts to slip. Similarly, high ambient temperatures can cause cooling water systems to operate at values higher than their design range which can also cause units to trip when unsafe temperatures are reached.

b. Stations and mining houses do not have blending facilities which results in pre-certified coal entering the station in batches. Batches of coal burn differently and may sometimes require fuel oil usage to prevent unit trips.

c. Combustion equipment such as pumps, burners and heaters can sometimes be unreliable due to obsolescence, design deficiencies or incur breakdowns due to defects.

d. There are occasions when routine sootblowing cannot be performed such as during periods of high demin water consumption or when the unit is constrained to operate at lower loads (e.g. when a trip risk exists at higher loads or there is a plant defect which results in high air to fuel ratios causing a loss of performance). If sootblowing is stopped for too long, the ash accumulation may eventually result in a unit trip or result in high boiler flue gas temperatures can cause damage to any plant equipment downstream of the boiler.

e. Instrumentation can become unreliable if routine maintenance is not conducted. The signal may stop functioning completely or may drift out of range. During periods such as this, units can become unstable and may trip.

f. If production is prioritised and the unit is constrained on load (e.g. operating unit with confirmed boiler tube leaks), it sometimes happens that the defect increases over time until eventually the equipment fails catastrophically and the unit is forced to shut down earlier than the planned outage date.

iii. Safety management

a. Panel controllers are required to maintain safe boiler operating conditions through the selective use of fuel oil to prevent trips during transient conditions. Should the unit be deemed to be too unsafe to stay on load, the operator is trained to initiate a controlled shutdown to mitigate the risk.

b. Plant defects or instrument failures sometimes require that units be operated on manual. This requires the use of temporary operating procedures. Trip risks typically increase during these periods as operators cannot respond as quickly as automatic control systems.

iv. Maintenance

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

b. Several mid-life refurbishment projects have been deferred due to funding constraints which will negatively impact plant reliability.

v. Operating practices

a. Staff shortages exist at most power stations and can result in routine planned maintenance and standby or running checks not being done and this may negatively impact the units reliability and efficiency over time.

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

Table 30: NERSA Decision vs Actual volumes

Start-up Gas & Oil Consumption Volumes (Litres)	Decision FY2023	Actual FY2023
Start-up gas & oil	409 555 556 *	619 737 575

**Note: According to Nersa RfD for FY2023, the decision price (i.e R9.00) multiplied to decision volume (i.e 400 000 000 Litres) does not equal to decision amount of R3686m. Hence the decision volume was assumed to be 409 555 556 Litres in order to balance to decision amount of R3686m.*

Fuel oil is used to assist in stabilizing combustion within coal-fired boilers, typically during transient conditions, and may be required due to sudden load changes, plant defects or out-of-specification coal properties. The most significant fuel oil consumption rate is during a cold start-up of a unit when a unit has been off for more than 36 hours. Start-ups occur after planned and unplanned outages and trips. The 736 automatic trips of FY2023 were higher than the automatic trips of FY2022 and were the result of plant equipment unavailability and reliability challenges.

The high fuel oil usage was caused by a combination of factors such as aging equipment, spares obsolescence and unexpected plant breakdowns and other operating conditions which required the crews for normal planned maintenance to be re-assigned to clear plant breakdowns and production losses.

In general, the main contributors to trips were the mills, electric feed pumps, boiler combustion and other variables related to control or instrumentation equipment. Recovery plans were site specific to address root causes and operating conditions as the maintenance history and coal qualities of each station is unique to that site.

Further, it should be noted that in the current environment of the generating units' performance being unpredictable, the use of fuel oil for combustion support assists in keeping a unit running (continue providing energy to the system), thereby circumventing increased loadshedding.

The root cause of the current plant condition was Eskom not being allowed to increase capacity. This led to the high utilisation of the plant and inadequate maintenance (eg. Mid-life refurbishment not performed as per OEM maintenance philosophy), consequentially resulting in the deterioration in performance. The capacity expansion decision was outside of Eskom's control.

The extended procurement lead times for spares and skilled maintenance support staff caused delays with efforts to restore plant redundancy resulting in some units operating for extended periods with higher fuel oil usage. Generation has already put a number of security related and technical control measures in place to provide assurance of fuel oil deliveries and usage to ensure that an audit trail is created for all fuel oil delivered and used on site. The most significant technical project is called the Fuel oil Management System (FOMS) which was piloted at Kendal and Majuba power stations in 2010 and is the current preferred solution to provide assurance. The root causes of the high fuel oil usage is tracked regularly and stations are expected to provide details of progress updates of fuel oil reduction plans and execution activities. Lastly, procurement and contract management controls were also reviewed to ensure that suppliers are held accountable for the quality and quantity of their deliveries through onsite and offsite testing processes and that prices are market related.

Table 31: NERSA Decision vs Actual volumes (litres) and price (R/litre)

Start-up Gas & Oil Average R/Litre	Decision	Actual FY2023
Start-up gas & oil	9.00	14.21

- **Average Price variance**
  - Calculation: *(Actual price - Decision price) x Actual litres = (14.21 – 9.00) x 619 737 575 =* ***3 229 518 566***
  - The price of the start-up gas and oil is driven by the US Dollar oil price and the R/$ exchange rate. A significant variance in the price assumed in the decision and the actual price is illustrated in the table above.

- **Volume variance**
  - Calculation: *(Actual litres -Decision litres) x Decision price = (619 737 575 – 409 555 556) x 9.00 =* ***1 891 638 175***
- **Total Variance =** ***R5 121 156 741***

As noted from the price and volume variances quantified above, the RCA variance is largely driven by prices being higher than what NERSA assumed in the determination. The volumes were also higher than NERSA determination. To re-emphasise, *in the current environment of the generating units' performance being unpredictable, the use of fuel oil for combustion support assists in keeping a unit running (ie. continue providing MWs to the system), thereby circumventing increased loadshedding. It needs to be noted that in the absence of utilisation of additional fuel oil to restart units, the level of loadshedding would likely be much higher. Thus, every effort needed to be made minimise loadshedding to support the economy of the country.*

9.7 Nuclear Fuel costs

Table 32: Variance in nuclear fuel

Nuclear Fuel (R'm)	Decision FY2023	Actuals FY2023	Variance
Nuclear fuel costs	751	674	(77)

The fuel used at Koeberg Power Station is wholly imported. Consequently, international benchmarks (Rand per kilogram) were used to determine the approved price. The table below indicates the main reasons for the nuclear fuel costs differing from what was allowed in the NERSA decision. Variances in nuclear fuel costs are explained in the table below.

Table 33: Reasons for variance in nuclear fuel

Nuclear Primary Energy (R'm)	Decision FY2023	Actuals FY2023	Variance	Explanations
Nuclear fuel other	81	53	(28)	see table below
Nuclear Unit 1 usage	560	279	(48)	Outage 126 originally planned to start on 17 October 2022 according to rev 72 of production plan for a duration of 90 days. A revised production plan of Rev74 was issued with a revised start date 10 December 2022 for extended duration outage of 185 days.
Nuclear Unit 2 usage		234		Due to delayed end date of outage 225, Originally planned end date was 7 June 2022 - Unit 2 synchronised on 7 August 2022, however during startup rod misalignments were experienced, resulting in the unit tripping and was offline again from 03 September till 26 September 2022.
Nuclear Spent Fuel	110	109	(1)	Lower depreciation due to lower spent fuel assets capitalised due to Outage 126 completion moved to next FY
Total Nuclear Primary Energy	**751**	**674**	**(77)**	

Table 34: Nuclear Fuel Other

Nuclear Fuel Other (R'm)	Decision FY2023	Actuals FY2023	Variance	Explanations
Fuel Write off - Outage 225	48	17	(31)	Fuel write off less than planned. Application was based on estimates
Fuel Write off - Outage126		0		Outage 126 write off moved to next financial year
Adhoc Fuel Studies	33	14	3	Additional ad hoc studies to due changes in production plan scenarios
Fuel Assembly Repair - (*2)		20		Fuel repair originally planned for the previous financial year. Due to availability of the plant and foreign resources could only be done in current financial year
Fuel Studies amortisation		2		
Total Nuclear fuel other	**81**	**53**	**(28)**	

The nuclear fuel costs were based on a production plan 72 issued in August 2020. Since then, the production plan has seen several revisions with the current production plan sitting on Rev 74.

Changes in production plans were driven by the following factors:

- Increased outage durations for various reasons (delays, extended work, modifications shifting to later outages increasing the durations of the future outages)
- COVID 19 impact on unit 2 in the 2021 Financial year. Country wide reduction of electricity usage during to the COVID-19 lockdown, Unit 2 was taken offline on 3 April 2020 till 13 July 2020 and outage 224 start date was deferred to August till October 2020 (planned start date was originally 27 April till 14 June). This resulted in outage 225 start date moving from 04 October 2021 to only start in 18 January 2022 and end date moving to the next financial year.
- Outage 225 for rev 72 catered for the Steam Generator Replacement to take place. Rev 72 had an outage duration of 130 days planned.
- A decision was made to not replace the Steam Generators in outage 225 in March 2022 and it was deferred to the next outage.

10 Demand Response and Power Alerts

10.1 Demand Response

10.1.1 Demand Response Actuals vs NERSA decision

Focus was on the management of the Demand Respond programme. Demand Response provides the System Operator with key levers, namely, instantaneous, and supplemental products to meet the daily system operating reserve margins. The actuals for FY2023 vs the decision is outlined in the table below.

Table 35: Breakdown of Demand Response (R'm)

Demand Response (R'm)	Decision FY2023	Actuals FY2023	Variance
Instantaneous (Rm)	-	141	-
Supplemental (Rm)	-	126	-
Programme Admin cost	-	31	-
Total programme costs	**381**	**298**	**(83)**

Table 36: Breakdown of Demand Response (MW/GWh)

DR Category	Application FY2023	Nersa Adjustment	Decision FY2023	Actual FY2023	Variance	RCA Adjustment	RCA FY2023
Instantaneous (MW)	600	0	600	1019	419	(419)	0
Supplemental (MW)	350	0	350	428	78	(78)	0
Supplemental (GWh)	105	0	105	78	(27)	27	0

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

10.1.2 Reason for the Demand Response Actuals for FY2023

NERSA has determined R421m revenue related to Demand Response (DR) in FY2023. The actual expenditure for this year was R357m. The reason for the variance is due to economic conditions and commodity price fluctuations which resulted in many of the participating load providers not being available to be dispatched. It must be noted that the DR expenditure is a function of usage (the lower the usage, the lower the expenditure).

DR is crucial in ensuring security of supply for any system. DR is an appropriate lever as it used over short periods, allows the customer the flexibility to make up production at different times of the day and is a lower cost than running open cycle gas turbines.

The System Operator (SO) is responsible for the reliability and security of the South African national electricity grid by monitoring, controlling, and operating it in a safe, economical and reliable manner.

The Demand Response programme provides the SO with flexibility and reliability to maintain adequate daily operating reserve margins to cater for unforeseen circumstances that could affect the stability of the supply.

Factors that could affect the stability of the electricity supply include:

- System constraints caused by severe weather and/or power line issues
- Generator malfunctions (unexpected trips – loss of multiple GX units)

DR is catered for in the daily operating reserves of the SO (even during times of surplus capacity) as part of normal system operations and is dispatched only when needed like other modern utilities around the world.

The two key reserves provided by the Demand Response programme are:

a) Instantaneous Reserve

A consumer of electricity is contracted with, to drop a certain pre-determined amount of load, to counter act a fall in the system frequency. The purpose of Instantaneous Reserve is to keep the frequency at acceptable limits following contingency incident, for example a generator trip. The automatic action from the customer must respond fully within 10 seconds and must be sustained for at least 10 minutes. The system is more vulnerable in the late afternoon. The combined effect of the reducing generation capacity of the sun-based generation sources in the late afternoon and the sudden increase in demand in the evening has a large impact on the demand-supply balance. Instantaneous Demand Response is an ideal mechanism to manage this high demand period – if this balance becomes unstable; the contracted customers' load automatically reduces to alleviate the problem and restore balance.

b) Supplemental Reserves

Supplemental Demand Response refers to customer loads that can be voluntarily reduced (for compensation) by customers. They are required to respond within a minimum notice period of 30 minutes, thus assisting Eskom to avoid using the expensive open cycle gas turbines. This mechanism is contracted with the customer annually and works on a bid available day-ahead. It is required to ensure an acceptable day-ahead risk, and to allow time for plant to be started up.

The DR products are typically scheduled and dispatched before Eskom's emergency reserves. By placing DR in this merit order, DR has proved to be a cost saving tool (economic dispatch) by reducing the need of using Eskom's peaking stations (gas turbines), as well as extending the Eskom's fleet of resources. Furthermore, the Demand Response programme will be required by the system operator even after a healthy reserve margin is established. This is due to the need to deal with unforeseen events on a daily and hourly basis such as higher than expected demand and plant trips, particularly in view of the technical risks associated with the significant levels of renewable power stations to be connected to the grid. The Eskom Demand Response programme is considered as best practice for modern system operators and should continue.

10.2 Power Alert

10.2.1 Power Alert Actuals vs NERSA decision

The Power Alert system is a real-time system using television broadcasts during evening peak periods (17:00 to 21:00) to inform the South African public about the status of the electricity network. These alerts are colour-coded messages, indicating the four stages in electricity status levels (green, orange, red and black). More importantly, the alerts are supported with information about the actions required from the target audience to reduce their electricity consumption to reduce the constrained situation and avoid or limit the stages and duration of loadshedding. The Power Alert television broadcasts from April 2022 to March 2023 had an average of 580 alerts, reaching approximately 20,4 million viewers monthly, playing a critical role in keeping the public informed and providing daily system updates. The actuals for FY2023 vs the NERSA decision are outlined in the table below.

Table 37: Breakdown of Power Alert (R'm)

Power Alert (R'm)	Application FY2023	NERSA Adjustment	Decision FY2023	Actuals FY2023	RCA FY2023
Total programme costs	78	(38)	40	59	19

10.3 Reason for the Power Alert Actuals for FY2023

NERSA determined a R40m revenue related to Power Alert in FY2023. The actual expenditure for this year was R59m. The reason for the variance is due to the increased media placements to broadcast the Power Alerts on all relevant television stations, namely SABC, DStv, ETV and OVHD. This was to ensure the best possible reach across all the electricity users in South Africa - lower, middle and higher income users - ensuring that the public is well informed and requesting them to assist in reducing the strain on the national grid. The 2023 financial year recorded the highest instances of loadshedding - 280 days (compared to 65 days in 2022), which meant that residential voluntary electricity reduction was critical.

11 Open Cycle Gas Turbines (OCGT's)

The usage and cost of open cycle gas turbines are allowed as pass-through costs subject to prudency review of volumes. The current year volumes exceed that assumed in the FY2023 decision as highlighted in the MYPD Methodology.

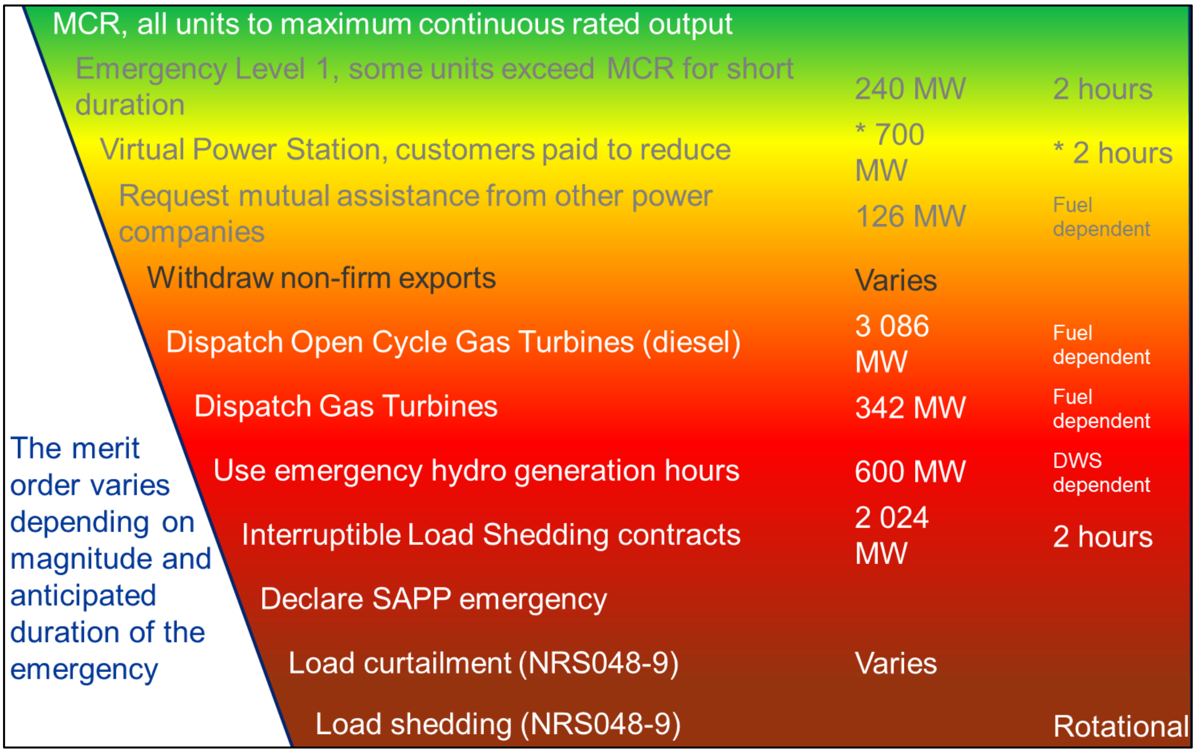
11.1 The MYPD Methodology states the following:

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

11.2 OCGT Dispatch

The usage and cost of open cycle gas turbines are allowed as pass-through costs subject to prudency review of volumes. The current year volumes exceed that assumed in the MYPD decision as highlighted in the MYPD Methodology. In accordance with the MYPD Methodology, the gas turbine usage should be allowed as it was incurred to ensure security of supply and was done so as a last resort before the implementation of load shedding.

Figure 16: The System Operator merit order for emergency resources



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

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

11.3 System operator use of OCGTs in FY2023

The high usage was essential to minimise loadshedding. The root cause of the reduced availability was capacity and financial constraints requiring high utilisation factors over a prolonged period, more than a decade, leading to high wear and tear on systems and components. The details on the certain usage of OCGT is also demonstrated in the document where each incident of loadshedding is described. This directly demonstrates that if OCGT was not utilised, the extent of loadshedding would have been significantly worse.

It is acknowledged that Eskom plants and the especially IPP plants did not produce energy, as determined by NERSA in the revenue decision. The details are provided in the Production Planning section, earlier in this document. In summary, Eskom's coal fired power plant produced more energy in this financial year than originally assumed in the June 2021 application and over 99% of energy assumed in the updated application of January 2022. The IPPs produced approximately 50% of energy when compared to that originally assumed by the relevant Government Departments in the June 2021 application. It is submitted that the details of the reasons for this would need to be considered. Thus, it is understood that neither

Eskom nor the IPPs made any commitments (or promises) that a particular outcome would materialise. The purpose of the RCA process is to ascertain the reasons for the variance, from the determination made by NERSA, are prudent.

When assessing the motivations for the increased utilization of OCGTs the status of the overall electricity supply industry must be taken into account. Eskom is operating in a constrained environment as a result of various factors.

The independent System Operator is guided by the Grid Code and acts independently when dispatching the various plants. Given the constrained environment, the OCGT plants (both IPPs and Eskom) are called upon to meet the necessary demand. Once the IPP OCGT has been utilized the only other peaking plant available is the Eskom OCGTs to assist with minimizing load shedding and thereby taking on a country role to meet the demand. The usage of these peaking plants should be treated equally and the assessment of the increased usage of Eskom OCGTs should be taken in this context. The Eskom OCGT plants should not be discriminated against the backdrop of the rest of Eskom's fleet but should be assessed in terms of being dispatched by the System Operator in terms of its licence conditions to protect the integrated power system prior to implementing load shedding. The DoE IPP Peakers have been given full recovery for costs incurred, but this is not the case when NERSA assess Eskom OCGTs just given the fact that it is under the Eskom banner.

Additionally, in previous RCA decisions, it has been incorrectly assumed that the use of additional Eskom OCGTs is due to Eskom coal fired power plants not being available. As clarified in the production plan section, it is mainly the IPPs that were not available to deliver, as originally planned that could be one of the key reasons for the use of further Eskom and IPP OCGT plants. When NERSA correctly determined that certain IPP projects will not be operationalised as determined by the Government Departments, it assumed that Eskom's coal fired power plant would automatically increase their ability to produce this shortfall in energy. No details of the capacity to do so was illustrated in the NERSA revenue determination.

It should also be noted that some of the original shortfall in IPP production was already accommodated by a severe increase in the energy utilization factor (EUF). This results in operating many of the Eskom coal fired power stations at the absolute maximum ability and likely to result in further unplanned outages. It needs to be acknowledged that any improvement in performance of Eskom coal fired power stations will possibly assist in the balancing of the system requirements as well as possibly decrease the level of load shedding. However, the reasons for these challenges are expanded below.

It should be noted that the electricity industry is a long-term industry. Decisions made, or decisions not made, have a long-term impact on the operations of the business. Thus, it is unfortunate that certain historical events have long lasting impacts. The challenges being faced by the country presently bears testimony to this situation.

The variance in utilisation of Eskom and IPP OCGT plants were due to a minimisation of load shedding. If the OCGT plants were not utilised, then additional load shedding would have occurred. This illustrates the compliance to the MYPD methodology, where OCGTs would be utilised as a last resort before loadshedding is implemented by the System Operator. The variance for diesel cost applied for in the FY2023 RCA related to an energy volume variance of 3018GWh, compared to decision of 733GWh is further motivated. It is submitted that when clarifying whether this variance is "under management control", it is correct that decisions were made by Eskom management, specifically the System Operator. However, the overwhelming situation in the country needs to be considered. Many factors that provide a limit to the decisions that could be made to ensure that Eskom meets the demand. It should also be noted that certain coal fired plants were utilised to a greater extent than was envisaged in the Eskom revenue application. Thus, any available capacity was utilised before resorting the use of IPP or Eskom OCGT plants.

There are two sources of supply where shortfall was experienced – the IPPs and Eskom generation. The shortfall of energy from IPPs has been demonstrated. In the past, NERSA allowed the full recovery of IPP costs for OCGTs due to shortfall in the renewable programmes. As far as Eskom generation is concerned, a multitude of factors need to be considered in terms of the NERSA prudency guidelines, as to whether correct management decisions were made to run the OCGTs. Eskom has demonstrated that the System Operator has to make decisions to dispatch OCGT plants (Eskom or IPP) in an environment that is severely constrained by the lack of sufficient generating capacity (caused partly by investment decisions not being timeously made), undertake thorough maintenance regimes (related to lack of space), manage within constrained budgets (due to shortfalls in NERSA revenue decisions) to ensure that relevant skilled employees are always available, challenges possibly posed by Government procurement requirements, working with the majority of the generation fleet being close to decommissioning.

11.3.1 OCGT fuel pricing and volumes per station

Table 38: Summary of OCGT fuel costs

OCGT cost (R'm)	Decision FY2023	Actuals FY2023	Variance
Ankerlig		9 288	
Gourikwa		11 936	
Acacia		0	
Port Rex		27	
Ankerlig storage & demurage		72	
Gourikwa storage & demurage		32	
Total	**3 753**	**21 355**	**17 602**

Table 39: OCGT production per station (GWh)

OCGT production (Gwh)	Decision FY2023	Actuals FY2023	Variance
Ankerlig		1 332	
Gourikwa		1 681	
Acacia		1	
Port Rex		3	
Total Gwh	**733**	**3 018**	**2 285**

Table 40: OCGT fuel burn

OCGT Fuel burn (litres)	Decision FY2023	Actuals FY2023	Variance
Ankerlig		418 610 227	
Gourikwa		517 390 145	
Acacia		414 371	
Port Rex		1 093 406	
Total Litres	**234 560**	**937 508 149**	**937 273 589**

Note: it appears that Nersa made an error in the calculation of the diesel litres (refer to Para 6.3.30 of the Nersa RfD). According to the logic applied in this paragraph it should've been 234 560 000 litres and not 234 560 litres

Table 41: OCGT fuel cost R/litre

OCGT Fuel burn (R/Litre)	Decision FY2023	Actuals FY2023	Variance
Ankerlig	16.00	22.36	6.36
Gourikwa	16.00	23.13	7.13
Acacia	13.00	- 0.80	- 13.80
Port Rex	9.80	24.74	14.94
Average R/Litre	16.00	22.78	6.78

Table 42: OCGT Cost (R/MWh)

OCGT Cost (R/MWh)	Application FY2023	Decision FY2023	Actuals FY2023	Variance
Average R/MWh	4 465.21	5 120.05	7 076.31	1 956.26

- **Price Variance** = *(Actual price - Decision price) x Actual Energy*

  (R7076.31/MWh - R5120.05/MWh) x 3018 GWh = R5 903 563 884

- **Volume Variance** = *(Actual Energy - Decision Energy) x Decision Price*

  (3018 GWh – 733 GWh) x R5120.05/MWh = R11 698 236 323.04

- **Total Variance** = ***R17 601 800 208***

11.4 Conclusion on OCGT's

It is submitted that Eskom System Operator has dispatched OCGTs in accordance with the NERSA MYPD methodology. The variances between the assumptions in the decision and actuals for FY2023 illustrate the need for the use of OCGTs – both Eskom and IPP OCGTs - to the extent required to minimise the impact of loadshedding on the South African economy. The overall economic impact of loadshedding has thus been minimised. A portion of the variance is due to the increased price of the fuel compared to the NERSA decision.

12 Independent Power Producers

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

12.1 Legal basis for IPPs per the MYPD Methodology

12.2 IPP Approvals

All the IPP Power Purchase Agreements (PPA) entered into were approved as part of the licensing process by NERSA prior to being finalised and signed. Eskom has secured recovery of costs associated with all IPP contracts in accordance with the regulatory rules for power purchase cost recovery as well as section 13 of the MYPD methodology.

12.3 Allowed vs Actual IPP costs for FY2023

Table 43: Adjustments to AFS to derive final RCA Actuals

Actual FY2023	R'm
Annual Financial Statements (AFS)	**41 765**
Add: Capacity payments for DOE Peakers (capitalised under IFRS)	1 635
Add: Capacity payments for DOE Peakers (accrual for Avon and Dedisa)	133
RCA Actuals	**43 534**

The NERSA determination with regards to revenue related to IPP costs for the FY2023 in the MYPD 5 decision was R43 130m. Total IPP costs for the FY2023 RCA is R43 534m, including the capacity payment for the DOE Peakers (which is capitalized as a lease payment for financial reporting purposes). A summary of the costs and volumes from IPPs are presented in the table below:

Table 44: IPP costs and volumes

Independent Power Producers	Cost (R'm)			Volumes (GWh)			Average costs (R'm)		
FY2023	**Decision**	**Actuals**	**Variance**	**Decision**	**Actuals**	**Variance**	**Decision**	**Actuals**	**Variance**
Renewable IPP Programme	37 898	33 479	(4 419)	19 370	16 859	(2 511)	1 957	1 986	29
DoE Peaker	4 946	10 055	5 109	596	1 098	503	8 305	9 156	852
Total IPP's	**42 844**	**43 534**	**690**	**19 965**	**17 957**	**(2 008)**	**2 146**	**2 424**	**278**
Network pass-through	286	-	(286)	-	-	-	-	-	-
Total IPP's	**43 130**	**43 534**	**404**	**19 965**	**17 957**	**(2 008)**	**2 160**	**2 424**	**264**
Less: current year provisions raised			-						
Add: Reveral of prior provisions			-						
Total IPP cost for RCA			**404**						

12.4 Reasons for IPP variances in FY2023

Eskom utilised 2 008 GWh less energy from IPPs when compared to the regulatory decision during FY2023. The average costs for IPPs were resulting in actual expenditure of R404m more than the decision.

12.4.1 Renewable IPPs

- **Price variance:** The renewable IPP average price was R29/MWh more than the NERSA determination due to lower output from wind generation (which is cheaper than solar photo-voltaic and concentrating solar power) than that expected at the time of application.

- **Volume variance:** The volumes produced by REIPP generators were significantly lower than that assumed in the NERSA determination due to project delays.

12.4.2 UoS charges

The use-of-system charges incurred by the IPPs are a pass-through under the PPA to the Buyer. The total charges included in the total above is R299.46m. This principle has been addressed in the High Court judgements of the review of the NERSA FY2019 revenue decision as well as the review of the NERSA RCA decisions for FYs 2015 to 2017.

12.4.3 DOE Peaker

- **Price variance:** The payment to the Peaker is split between capacity payments and energy payments as it is fully dispatched by Eskom.
- **Volume variance:** As explained above the volumes were higher, due to higher utilisation by the System Operator. With an increasingly tight capacity situation, compounded by the lower REIPPP output that expected, the System Operator was forced to utilize more diesel generation (from the Eskom fleet as well as the DoE peaker).

13 International purchases

13.1 International purchases variance

Eskom acquired electricity from neighboring countries that resulted in purchases of R6 459m which generated energy inflows during the year. The details of the variance between the actuals and the decision are outlined in the table below.

Table 45: International purchases

International Purchases (R'm)	Decision FY2023	Actuals FY2023	Variance
International Purchases	4 589	6 459	1 870

13.2 Cross-border purchases of electricity

The majority of cross–border purchases are from Hidroelectrica de Cahora Bassa (HCB) which is a hydro electrical plant in Mozambique. During the FY2023, HCB performed better than its historical trend as used in the MYPD application. When HCB performs higher than their Contractual Maximum Demand (CMD) of 1 150MW consistently, the energy cost and Reliability Premium costs as per the bilateral contract, increases. Furthermore, Eskom pays a higher rate to HCB, for any excess power supplied. In summary, this improved performance resulted in higher volumes being purchased, at a higher rate than in the application, and hence at a higher overall cost to the contract. Furthermore, the contract provides for a 5 yearly tariff reset based on the avoided cost of Eskom generation and transmission. The calculation is based on the most recent Eskom AFS, whose outcome could not be reasonably determined at the time of the application. The new tariff is effective 1 January 2023, covering portion of the above period.

14 Environmental levy

14.1 Allowed vs Actual Environmental levy costs for FY2023

Table 46: Environmental levy cost calculation of RCA balance (R'm)

Environmental Levy	Decision FY2023	Actuals FY2023	Variance
Non-Renewable energy sent out	188 153	183 952	(4 201)
Add: Auxilliary volumes	15 634	16 990	1 356
Generating Volumes	**203 787**	**200 942**	**(2 845)**
Rate in c/kWh	3.5	3.5	3.5
Generation Environmental Levy Cost	**7 133**	**7 033**	**(100)**

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

16. Taxes and Levies (not income taxes)

16.1 The Government imposes certain taxes and levies that are payable by Eskom.

16.2 Levies are any charges that the Government may impose and payable by Eskom arising from its licensed activity.

16.3 Taxes are any amount arising from an enacted legislation that the Government may require Eskom to pay which amount will be calculated in terms of such legislation.

16.4 Principles regarding taxes and levies

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

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

16.4.3 Eskom must ensure that the cost of the taxes and levies is specified and that the calculation thereof is clear and concise.

16.4.4 The amount provided for the taxes and levies must be ring-fenced and any over or under-

14.2 Environmental levy cost dynamics

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

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

15 Regulatory Asset Base Adjustments

15.1 NERSA Regulatory Asset Base (RAB) in FY2023 revenue decision

The RCA addresses the variances between the NERSA revenue decisions with the actuals that materialise. Eskom has maintained the decision RAB value for depreciated replacement value (DRC). This refers to the valuation exercise undertaken by external consultants. The High Court order related to the correction of the FY2023 RAB value (as outlined previously) refers. The joint order requires the correction of the RAB value in a subsequent decision by NERSA. This is from FY2024.

15.2 Basis of RCA application

15.2.1 MYPD Methodology requirements

The RCA balance application in respect of return on assets and depreciation for FY2023 differs from MYPD3 period in that all movements in the RAB are now re-measurable (Para 17.2.6.2) as opposed to only variances due to capital expenditure for the MYPD3 period.

15.2.2 Implementation of methodology and court judgement

RCA balance application includes depreciation and return on assets as shown in the table below.

Table 47: RAB and return on assets variance

RAB and RoA	Decision FY2023	Actual FY2023	Variance
Depreciated Replacement Costs (DRC)	427 093	427 093	-
Completed assets after FY2016	17 353	126 134	108 781
Asset purchases	1 779	2 010	231
Work Under Construction (WUC)	59 143	87 359	28 216
Working capital	59 736	52 621	(7 115)
Assets funded by customers upfront	(14 596)	(12 437)	2 159
Closing RAB values	**550 508**	**682 780**	**132 272**
Average RAB Values per Table 1 of the RfD	702 931	769 067	66 136
Percentage Return on Assets	1.08%	1.08%	
Return	**7 557**	**8 268**	**711**

Significant variances were observed in work under construction and completed assets post valuation.

15.2.2.1 Depreciation

The variance in the depreciation is driven primarily by the higher transfer to Commercial operations when compared to the decision.

Table 48: Depreciation variance

Depreciation	Decision FY2023	Actual FY2023	Variance
Fixed assets - DRC Values	41 642	41 642	-
Fixed assets - Transfers to CO	980	3 878	2 898
New Investments (Asset purchases)	445	503	58
Assets funded by customers upfront	(746)	(872)	(126)
Total	**42 321**	**45 151**	**2 830**

15.2.2.2 Transfer to commercial operations

Significant variances in the commissioning of Eskom's Generation, Transmission and Distribution capital projects occurred during FY2023 where the actuals were significant differences than the decision. The variance in generation assets transferred to commercial operation is reflected in the table below. NERSA had determined that no transfers to commercial operation in Generation will be made in this financial year. However, that is not the case. For both Transmission and Distribution, the transfer to commercial operation was lower than the decision, as reflected in the table below.

Table 49: Transfer to Commercial Operations (CO)

Transfer to Commercial Operation (CO)	Decision FY2023	Actual FY2023	Variance
Generation	-	41 613	41 613
Transmission	7 551	2 916	(4 635)
Distribution	10 782	2 288	(8 494)
Assets funded upfront by Customers	(758)	-	758
Transfers to Commercial Operations	**17 575**	**46 817**	**29 242**

16 Eskom Capital Expenditure

The table below reflects the actual capital expenditure for generation transmission and distribution in relation to the assumptions in the decision. The breakdown of capex per licensee is discussed in each section below.

Table 50: GTD capital expenditure (excludes asset purchases, DoE funded assets and IDC)

Capital expenditure excl. Asset purchases, DoE Funded and future fuel	Decision FY2023	Actual FY2023	Variance
Generation	41 044	21 851	(19 193)
Transmission	10 542	3 370	(7 172)
Distribution	8 279	4 562	(3 717)
Total	**59 865**	**29 783**	**(30 082)**

16.1 Generation Capital Expenditure for FY2023

Table 51: Summary of Generation Capex for FY2023

Generation Capex (R'm)	Application FY2023	Decision FY2023	Actuals FY2023	Variance
New Build and Major Projects	18 611		7 581	
Outage Capex	13 236		8 422	
Tech Plan Capex	9 156		3 642	
Renewables Capex	15		-	
Land & Rights			-	
Other			2 207	
Total Capex WUC	**41 018**	**41 044**	**21 852**	**(19 192)**
Nuclear future fuel	971		1 157	
Coal and water future fuel	2 230		1 704	
Asset Purchases	182		556	
Total Generation Capex	**44 401**		**25 270**	

The NERSA revenue determination for FY2023 states: “Eskom applied for a WUC of R90 422m, which is a cumulative balance from the inception of the Eskom build. This WUC has been disallowed, because the plants have been valued at the full value of plants in question. Only capital expenditures qualifying for transfers to WUC should be approved. These amount to R41 044m and are the capital expenditures that relate to the application year.”

16.1.1 New Build and major capital projects

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

Eskom continues to execute the major New Build projects which are Medupi and Kusile as well as Generation Coal and Clean Technology projects which includes refurbishment projects as well Emissions projects.

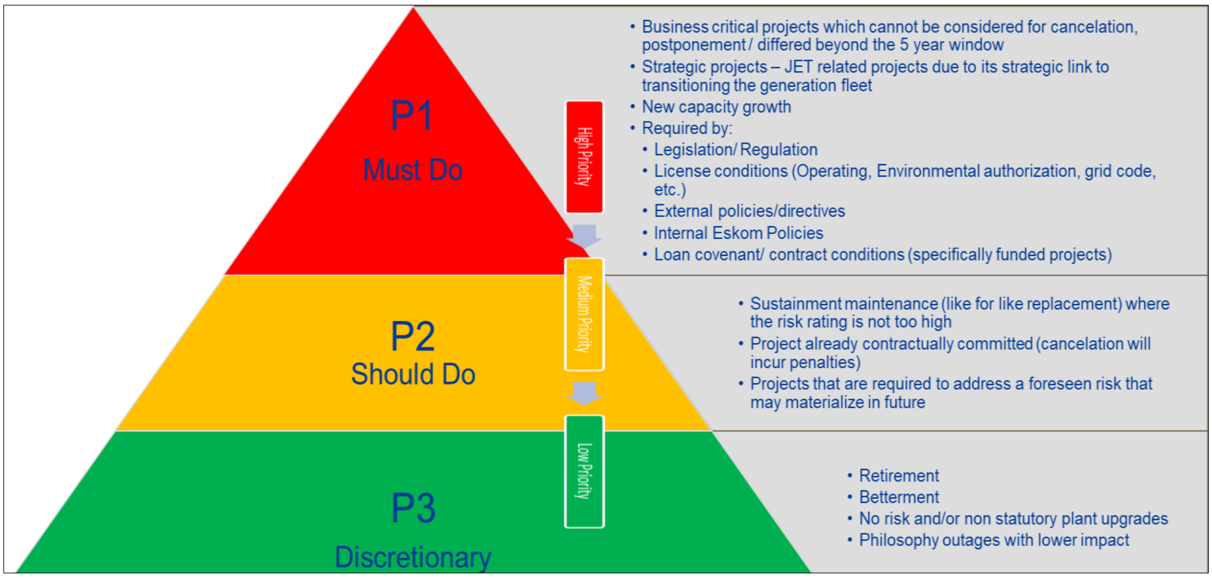
16.1.2 Outage and Technical Plan Capex

Outage and technical plan capex is critical to maintain the reliability of the power stations. Because of a lack of funding (mainly because of sub-cost reflective tariffs) and system space (because of the constrained country capacity situation), reliability maintenance cannot be executed as required, thereby affecting plant reliability, which ultimately leads to the loadshedding currently being experienced.

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

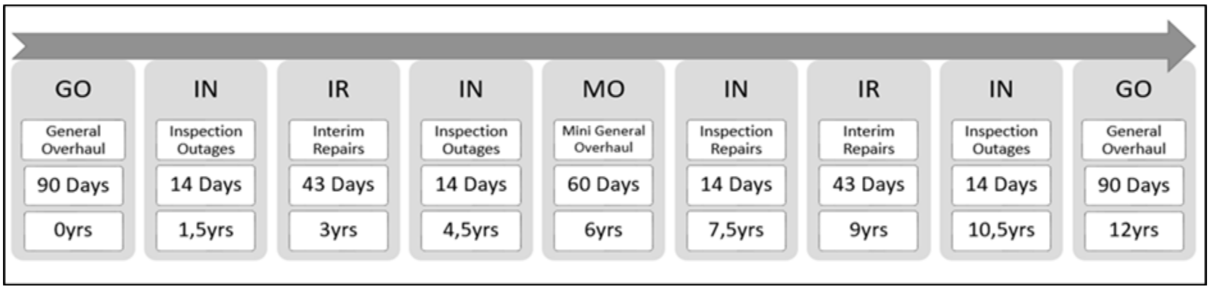
- The capacity planning process requires, as its main input, the long-range demand forecast less the forecasted renewables contribution (residual demand). This is the demand expected to be supplied by Eskom and the Gas IPP's. The daily peak demand is then used for capacity planning.
- The next important assumption for planning purposes is predicting the expected UCLF of the fleet.
- In addition to the load forecast and expected UCLF an additional 2 200 MW of reserve margin is catered for. The total available capacity (~ 48 500 MW) less the sum of the load forecast, expected UCLF and reserve margin determines the available outage capacity per day. Outages are then slotted into these spaces and optimised **to minimise the capacity shortfall (ie. to reduce or minimise the risk of load shedding)**.
- Planned outages within the Generation fleet are grouped into priorities, ranging from priority 1 (P1) to priority 3 (P3) outages. P1 outages focus mainly on statutory (safety of personnel and plant) and environmental regulatory requirements and are ranked higher for **capital funding allocation and scheduling**. *These outages have the possibility for serious damage to plant if not executed and cannot be moved without a risk assessment being performed*. Priority 2 and 3 outages affect plant performance and reliability without resulting in major damage or safety of personnel. **The scheduling of these are more flexible and used to balance the risk of increasing stages of loadshedding**. The priority allocation model in Figure 1 clarifies the classification of different outages scheduled within the 12-month period based on each station's outage philosophy.

Figure 17: Priority 1 to 3 Allocation Model



- Each station has an outage philosophy which includes outages with varying scope and duration within the philosophy cycle (e.g. – 12 years). Figure 2 illustrates the outage philosophy cycle of Tutuka Power Station. Maintaining the philosophy outage cycle is critical to ensuring reliability. Not all outages required as per philosophy are able to be scheduled on time due to manage capacity constraints (risk and extent of loadshedding) or preparedness levels.

Figure 18: Tutuka Outage Philosophy cycle



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

- Short term weekend opportunity maintenance is scheduled weekly at STERF (Short-term Energy Review Forum) based on the available capacity due to lower demand. Weekend opportunities are mainly granted to address emergent risks to production.

- Peak demand profile is highest in winter with the lowest being in summer. This profile results in less space being available in winter for outages and increased space in summer as the demand reduces.

P1 outages affect plant and personnel safety and legislative compliance (licence to operate). These outages cannot be moved within defined periods or without a proper risk assessment being performed. More flexibility is applied to P2 and P3 to manage the short-term capacity constraints. Currently all P1 and a portion of P2 and P3 outages are accommodated within the outage schedule to minimise risk to production **while balancing the impact of loadshedding on the country's economic and social wellbeing**.

16.1.3 Coal & Water Future fuel capital expenditure

Eskom invested capital expenditure of R1 704m (excl IDC) against the assumption in the decision of R2 230m in FY2023. Historic underinvestment in the Cost-Plus mines continued to be corrected in FY2023, albeit at a lower than optimal rate. The slower rate is partially because Eskom is still experiencing cash flow challenges and must allocate funds according to priorities. This was due to lack of overall funding when the decision was made. Therefore, certain projects may not be funded. Other projects are approved conditionally, i.e., they may be executed only when funding becomes available. This leads to a lag in the implementation of projects. The nature of investing in coal mines with regards to cost plus mines is a long-term investment. The repercussions of the delay in, and the lack of, investment in preceding years is evident in the decline in production from the Cost-Plus mines.

There were three items that made up the bulk of the underspend in FY2023 compared to the application:

- the Kriel beneficiation plant, and the land for Kriel opencast pits 11 and 13: These two items are linked. Studies for the opencast development indicate that the cost will be excessive, so this has been put on hold for now. Consequently, the beneficiation plant has also been put on hold.

- the Khutala life extension projects. The latter is being conducted on a smaller scale to contain costs and to meet coal quality requirements. The underspend is a result of projects being rephased and savings.

16.1.4 Nuclear Future fuel

The actual nuclear future fuel capex was R1 179m. Nuclear fuel procurement (i.e Nuclear future fuel capex) comprises the acquisition of uranium, conversion, enrichment, and the fabrication of the fuel assemblies for nuclear fuel. Long-term contracts are established to ensure security of supply as well as availability of nuclear fuel at the appropriate time and within the prescribed quality standards. The Nuclear Fuel which is held in Inventory until such time as it is placed into the reactor and burnt.

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

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

Nuclear fuel costs mainly comprise four categories, being Uranium (48%), Uranium Conversion (8%), Uranium Enrichment (22%) and Fuel Assembly manufacturing (22%). The costs contribution per category depends on market prices and the ruling exchange rates and as per the latest available Term-market prices. The cost of the delivered nuclear fuel is expensed as part of Koeberg's primary energy costs over the period that the assemblies remain in the reactor, which is normally between 45 and 54 months. Thus, there is not a direct correlation between when the nuclear fuel procurement costs incurred and when it is expensed as primary energy costs.

16.2 Transmission Capital Expenditure

16.2.1 Background

The key transmission capital requirement drivers include:

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

Table below summarises the Transmission Capital application, NERSA revenue determination and actual expenditure for FY2023.

Table 52: Transmission capital expenditure

Transmission: Capex (R'm)	Application FY2023	Decision FY2023	Actual FY2023	Variance
Strengthening and Expansion	10 410	10 410	1 899	(8 511)
Asset Replacement	1 127	-	1 407	1 407
EIA and servitudes	132	132	64	(68)
Total Capex for WUC	**11 669**	**10 543**	**3 370**	**(7173)**
Asset Purchases	47	47	173	126
Total Transmission Capex	**11 716**	**10 589**	**3 543**	**(7 047)**

The MYPD 5 capital expenditure application assumption for FY2023 was for a total value of R11 716m and NERSA revenue determination assumption was a total of R10 589m. The applied Asset replacement of R1 127m was not allowed. Total capital expenditure of R3 543m was incurred in FY2023 resulting in a variance of R7 047 million against the NERSA decision.

16.2.2 Asset Replacement

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

16.2.3 System Strengthening & Expansion Investments

Eskom's ongoing funding challenges emanates from several factors within and outside the organisation including the impact of the current and previous NERSA's tariff determinations. Naturally the funding gap required management to re-prioritise capital expenditure between projects across different licensees and asset categories. The result being lower capex allocation to Transmission than allowed by the regulator. The overall lower expenditure in System Strengthening & Expansion Investments is a consequence of historic capex reductions in previous years, together with delays in obtaining environmental approvals and securing of land which impacts the number of projects handed over for execution. Transmission's FY2023 strengthening and expansion capital expenditure amounted to 88% of the internally approved capital budget. Lower than planned capital expenditure is primarily due to delays in placing contracts, delivery of materials as well as challenges in accessing sites due to bad weather and community unrests.

16.2.4 EIA and Servitudes

The variance of R68 million compared to the determined expenditure is primarily due to outstanding Environmental Management Programme (EMPr) reports from the environmental consultants, delay in acquisitions as well as protracted servitude negotiations. The timely completion of servitude acquisition process is dependent on different stakeholders outside Eskom control such landowners and tribal authorities (where transmission lines traverse), deceased estates, municipalities, the Department of Forestry, Fisheries and the Environment and the Deeds Office.

16.2.5 Completed & Commissioned Assets

Table 53: Transmission completed and commissioned assets.

Asset Category	Breakdown for Strengthening and expansion	Breakdown for EIA and Servitude	Breakdown for Refurbishment
Total Transmission Capital Expenditure (R'm)	**1 899**	**64**	**1 407**
Line Assets Capex (R'm)	1 467	63	109
Substation & Auxilliary Assets Capex (R'm)	432	1	1 298
Total Line Assets in km	**326.1**	**-**	
- 765kV	1.5	-	-
- 400kV	324.6	-	
- 275kV		-	-
- 132kV	-	-	-
- 88kV	-	-	-
Transformer installed capacity and commissioned (MVA)	**-**	**-**	**-**
		-	

16.2.6 Asset Purchases

Asset purchases includes all movable items that are purchased and ready to be used, e.g. equipment and vehicles and production equipment. Transmission asset purchases amounts to R173 million versus an allowed MYPD 5 decision of R47 million. The main reason for this deviation is the vehicle replacement project is expected started in FY2023 and expected to conclude in FY2024.

Table 54: Transmission Asset Purchases

Asset Purchases	R'm
Buildings and Facilities	0.2
Production Equipment	23.3
Computer Equipment	-
Computer software	0.5
Transport Equipment	148.7
Total	**172.8**

16.2.7 Replacement of Transmission Fleet

The replacement of Eskom vehicles is dependent upon the vehicle life cycle, maintenance cost or distance travelled as well as unforeseen replacements due to accidents, hijackings, or theft. The fleet is a critical resource as the business is dependent on reliable vehicles with fit for purpose fitments to transport employees in executing their daily duties. The vehicles were replaced in this financial year, as most of them had reached the end of useful economic life and the cost-benefit analysis indicated that it is more viable to replace tan to repair. Furthermore, the vehicles no longer met Transmission's safety requirements, and thus ad to be replaced.

The MYPD 5 revenue application did not include these costs as previously the fleet function in Eskom was a shared service, managed centrally. The Eskom's unbundling and divisionalisation required Transmission to establish and manage its own fleet function. A full evaluation of the existing fleet resources was conducted to determine the need for repairs, replacements as well as the need for additional vehicles to meet business requirements.

16.3 Distribution Capital Expenditure

Table 55: Distribution Capex

Total Capex (R'm)	Application FY2023	Decision FY2023	Actual FY2023	RCA FY2023
Direct Customers	1 282	1 282	1 137	(145)
Strengthening	1 857	1 857	717	(1 140)
Refurbishment	1 424	1 424	587	(837)
Land & Rights	39	39	-8	(47)
IPP Connections	430	430	19	(411)
BESS	3 247	3 247	2 109	(1 138)
Total Capex for WUC	**8 279**	**8 279**	**4 562**	**(3 717)**
Asset Purchases	564	564	150	(414)
Eskom funded	**8 843**	**8 843**	**4 712**	**(4 131)**

The FY2023 assumption for Distribution WUC capex was R8 279m. Eskom's funding constraints necessitated a lower allocation for capex. The capital programme was impacted by restrictions and had to be revised.

The reasons for the capex variances are as follows:

- Direct customers are end users that are supplied by Eskom. The customers in this category exclude prepaid customers that are electrified as part of the DMRE Electrification programme. The investment in direct customers is dependent on the number of quotes accepted by customers. Projects were negatively impacted by the slow economic growth and material unavailability. The country wide lockdown of 2020 is having a lasting negative effect on the number of customer applications for minor works projects.

- Network strengthening is the expansion and upgrading of plant to increase capacity or improve the quality of supply. The programme further ensures that network constraints are averted, in support of future load growth. The lack of material due to adverse market conditions on Procurement and labour contacts had a negative impact on the programme.
- The primary objective of refurbishment is to extend the life of the assets and the maintenance of expected performance levels. The lack of material due to negative market conditions on procurement and labour contacts. Some critical material manufactured locally were also impacted by the adverse weather conditions in KZN.
- Land and rights variances are due to delays with customer negotiations, permissions and challenges in acquiring land and rights.
- The Capital allocation for IPP provides for the shared network infrastructure that needs to be created to allow for the evacuation of power from the IPPs. The IPP is responsible for its own network establishment cost up to the point of connection. The required funding is for the related upstream strengthening projects which are borne by the Distributor in line with the Grid Code requirements. The lower expenditure is due to Eskom funding constraints.
- The expenditure required for asset purchases includes the acquisition and replacement of workshop and production equipment of a capital nature. This expenditure is required to expand, operate and maintain new and existing distribution network. Similarly, as with the other Capex items, Asset purchases was affected by lack of materials and adverse economic conditions.

17 Energy Efficiency and Demand Side Management (EEDSM)

17.1 Requirement for IDM

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

In particular, Distribution Demand Management Programme (DDMP) measures will also support the system operations by providing flexible services (dispatchable supply and demand) to maintain adequate operating reserve levels reducing evening peak demand in the industrial, commercial, agricultural and residential sectors, to manage grid stability and congestion on the local and national networks. DDMP measures continue to be used and have the capability to optimise capital expenditure on constrained networks by deferring network upgrades through localised demand-side management programmes where feasible.

Past experience has proven the valuable contribution EEDSM and DR programmes can make to stabilising the electricity system. The demand / supply situation is cyclical and maintaining the DDMP capacity is essential. More so, having DDMP capacity that uses the principle of efficient energy when required by business as a means to support both excess and constrained supply situations will be a considerable asset to the industry and the economy.

Due to the NERSA determination not to include any IDM in MYPD4, the IDM EEDSM programmes was put hold between FY19 to FY22. It should be noted that due to the capacity constraints in the country, the need to revive EEDSM programmes has become essential. This allows for an efficient way to reduce demand and has many other benefits. It takes time to reintroduce processes and is likely that further benefits will only be realised from FY 2024.

The OPEX spend of R41m for FY2023 include large percentage for Marketing, M&V and provisions for older EEDSM projects respectively.

Table 56: FY2022 EEDSM Operating costs

Other expenses (R'm)	Decision FY2023	Actual FY2023	Variance	RCA Adjustments	RCA FY2023
Employee benefits	-	20	20	-	20
Maintenance	-	-	-	-	-
Other Opex	-	41	41	-	41
Arrear Debt	-	-	-	-	-
Other income	-	(0)	(0)	-	(0)
Depreciation	-	0	0	-	0
Less: Corporate Social Investments	-	-	-	-	-
Total operating costs	-	60	60	-	60

18 Operating costs

Operating costs comprises employee benefits, maintenance, and other operating costs. It excludes IDM which is treated separately for RCA purposes.

MYPD Methodology - Operating costs – treatment for RCA

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

As required by the NERSA methodology, it is incumbent upon NERSA to determine the prudency of the variances submitted by Eskom. Eskom has provided detailed motivations for the variances from the NERSA decision, as required by the methodology.

It is also important for NERSA to consider the principles on operating costs, as reflected in the MYPD methodology (Section 10.4). Certain key principles are summarised here.

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

18.1 What is required by NERSA to assess operating costs

As required by the NERSA methodology, it is incumbent upon NERSA to determine the prudency of the variances submitted by Eskom. Detailed analysis of the latest projections needs to be undertaken to determine the prudent variance. It is understood that an adjustment (possibly by CPI) based on a previous decision does not amount to any analysis nor is there any evidence of prudency assessed. This goes against the intention of the methodology. Following this incorrect route could result in adjustments that negatively impact the consumer or Eskom.

18.2 Variances in Total Operating Costs

Table 57: Summary of Operating costs

Allowed operating costs (R'm)	Decision FY2023	Actual FY2023	Variance	RCA adjustments	RCA FY2023
Employee benefits (GTD,Cx,SAE&DSM)	26 833	28 207	1 374	-	1 374
Maintenance	20 195	22 045	1 850	-	1 850
Other Opex	11 996	17 365	5 369	(3 073)	2 296
Arrear Debt	-	12 774	12 774	(12 595)	178
Corporate Services (excl. EE benefits)	4 763	1 971	(2 792)	(74)	(2 866)
Other income	(1 173)	(3 914)	(2 742)	-	(2 742)
Less: Corporate Social Investment	(102)	0	102	-	102
Total Allowed Opex	**62 513**	**78 448**	**15 935**	**(15 742)**	**193**

The overall operating costs variance, after adjustments, is in favour of Eskom by a very slight amount. All elements of operating costs, with the exception of Corporate Services and other income illustrates variances in favour of Eskom. The key reason for this is that some operating activities have migrated to operating licensees from the Corporate Divisions. A key adjustment was for arrear debt, where NERSA has decided that arrear debt recovery will not be included in the revenue determination. Eskom had restricted the arrear debt application to 2% of allowable revenue. NERSA, in its decision commends Eskom for restricting the level of arrear debt to 2%, where the experience is in the region of 4% of allowable revenue. NERSA has in the past allowed at least 0.5% of allowable revenue to be recovered for arear debt. It is also noted that the Electricity Pricing Policy (EPP) recognises that recovery of arrear debt is acceptable. This is also a normal part of any business, including in the private sector. Even within the employee benefits category, the number of employees has decreased over the financial year. This is an area where further efficiencies have been achieved over the financial year. However, due to both the nature of the original employee benefit revenue decision as well as collective bargaining agreements over multiple years with Eskom's bargaining unit employees, the resulting employee benefits costs did not see a concomitant alignment. Maintenance variances in favour Eskom were driven by primarily variance within the Generation and Transmission divisions as discussed below. Significant variances were experienced within Corporate Services for the benefit of consumers which will be discussed in detail below.

18.2.1 Generation Operating costs

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

a. Total operating costs level

b. Maintenance costs in isolation

c. Number of employees in isolation

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

Table 58: Generation Operating Costs

Generation and SAE: Operating Costs	Decision FY2023	Actual FY2023	Variance	RCA adjustment	RCA FY2023
Employee expense	Eskom level	11 792	Eskom level	-	Eskom level
Maintenance	14 029	16 581	2 552	-	2 552
Other Opex	Eskom level	11 939	Eskom level	(2 852)	Eskom level
Arrear debt	-	-	-	-	-
Other Income	(427)	(2 875)	(2 448)	-	(2 448)
Less: Corporate Social Investments	-	-	-	-	-
Generation operating costs for RCA purposes		37 437		(2 852)	
Add: SAE operating costs for RCA (incl. arrear debt)	-	204	-	-	Eskom level
Total		**37 641**		**(2 852)**	

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

18.2.1.1 Generation's Total Opex in Perspective: Generation Total Opex Benchmarking

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

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

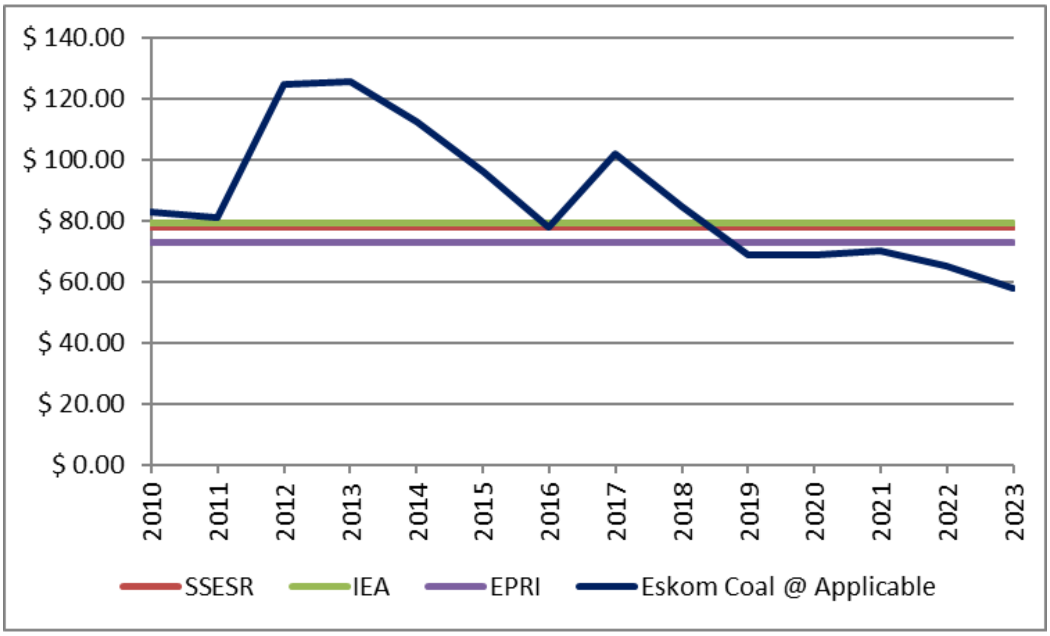
Table 59: Benchmark (FY2023)

	Total O&M ($/kW/Year)
SSESR	$77.80
IEA	$79.21
EPRI	$73.15

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

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

Figure 19: Benchmark compared to real O&M $/kW (coal stations only)



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

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

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

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

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

18.2.1.2 Conclusion on Generation Total Operating Cost

Generation benchmarked its Opex at three levels: (ie.

a) Total Opex Level (As per above);

b) Maintenance Costs in isolation (refer maintenance section);

c) Employee number in isolation (refer Employee Benefits section).

All three of these independent benchmarks revealed that Generation is operating within the norms (and even better) of these benchmarks.

However, this variance should be interpreted with due consideration to the impact on plant health and performance. This variance arose mainly as a result of funding constraints due to sub-cost reflective tariffs. *As stated on one of the benchmarking source reports, continued under-expenditure is unsustainable and poses a risk to operational sustainability.*

18.2.2 Variances in Transmission Operating Costs

Operating costs relate to all expenses incurred in the production and supply of electricity. These costs include employee benefits, maintenance, other operating costs, and corporate overheads.

Table 60: Variances in Transmission operating costs

Transmission: Operating Costs	Decision FY2023	Actual FY2023	Variance	RCA Adjustment	RCA FY2023
Employee expense	Eskom level	2 699	Eskom level	-	Eskom level
Maintenance	982	1 087	105	-	105
Other Opex	Eskom level	901	Eskom level	(151)	Eskom level
Arrear debt	-	-	-	-	-
Other Income	(107)	-150	(43)	-	(43)
Less: Corporate Social Investments	-	-	-	-	-
Operating costs for RCA purposes		**4 537**		**(151)**	

The NERSA determination for employee benefit expense, other operating cost and corporate overheads were made at an Eskom level. Therefore, variances at licensee level for these categories are compared to the MYPD 5 revenue application.

Total Transmission operating costs expenses is consistent with the MYPD 5 application. Maintenance costs has a variance of 13% owing to increased line, servitude, and transformer maintenance. Total other operating costs is 20% above what MYPD 5 application projections primarily due to abnormal transactions incurred. This is partly offset by variances in corporate overheads and other income received from insurance proceeds.

18.2.3 Variances in Distribution Operating Costs

Table 61: Distribution Operating Cost

Dx Operating Costs	Decision FY2023	Actual FY2023	Variance	RCA Adjustment	RCA FY2023
Employee benefit cost	Eskom level	11 606	Eskom level	0	Eskom level
Maintenance	5 184	4 378	(806)	0	(806)
Other expenses	Eskom level	4 481	Eskom level	(70)	Eskom level
Arrear debt	0	12 595	12 595	(12 595)	0
Other income	(509)	(890)	(381)	0	(381)
Less: Corporate Social Investments	0	0	-	0	-
Operating costs for RCA purposes		**32 170**		**(12 666)**	

The NERSA determination for employee benefit expense and other operating cost were made at an Eskom level. Therefore, variances at a licensee level for these categories can only be explained against the application. The operating costs variance for maintenance and other income is in favour of the consumer. In NERSA's decision for FY2023 arrear debt was not included therefore it has been adjusted and is not included in the RCA application.

18.3 Employee Benefit costs

Table 62: Summary of Employee Benefit Costs

Employee Benefit costs (R'm)	Decision FY2023	Actual FY2023	Variance
Generation	Eskom level	11 792	Eskom level
Transmission		2 699	
Distribution		11 606	
SAE		23	
IDM		20	
Corporate services		2 069	
TOTAL	**26 833**	**28 207**	**1 374**

18.3.1 Generation Employee Benefit costs

18.3.1.1 Introduction

Specific focus is placed, and attention is being given to the following initiatives because of their strategic importance and value to Generation sustainability and future success:

- Leadership and management development.
- Technical training;
- Skills audits and gap assessment;
- Implementation of new Generation operational structures aligned with the new generation strategy, mandate, and key objectives; and
- Generation has developed a clear path defining the skills and resource requirements over the planning period

18.3.1.2 Generation Employee numbers

Employee benefit costs are predominantly driven by employee numbers. The employee numbers of Generation for the FY2023 period are as follows:

Table 63: Generation employee numbers

Number of Employees	Application FY2023	Actuals FY2023
Generation Employee Numbers	12 724	13 237

18.3.1.2.1 EMPLOYEE NUMBER BENCHMARKING

The optimal number of employees cannot be determined by the level of sales (in GWh) since employee costs are not variable with production. In fact, the opposite is true in that employee costs are mostly fixed in nature in the short term. It is widely accepted world-wide, that for employee benefit analysis, **MW (generating capacity) per employee is the accepted norm used for benchmarking**. The clarification has been provided in previous RCA applications.

18.3.1.3 Generation Employee Benefit Cost

The NERSA FY2023 revenue reasons for decision did not apportion its decision per licensee for employee benefit costs. In the absence of such apportionment, the RCA motivation will be based on the prudency of actual expenditure.

Table 64: Generation Employee Benefit Cost

Employee benefit costs (R'm)	Actuals FY2023
Salaries	7 173
Overtime	1 325
Post-employment medical benefits	123
Leave	374
Pension benefits	876
Bonus costs/rewards	466
Allowances	1219
Employer contributions	691
Direct costs of employment	**12247**
Training and development	37
Temporary and contract staff costs	198
Other staff costs	203
Gross employee benefit expense	**12685**
Capitalised to property, plant and equipment	-893
Nett employee benefit expense	**11 792**

Employee benefit costs are mainly driven by:

a) The ***number of employees*** – Permanent employees and full time equivalent (FTE's)

b) The ***cost per employee*** - Salary adjustments and cost of living adjustments

Employee Benefits cost detail:

a) Salaries:

Approximately 78% of the Generation licensee staff complement belongs to the bargaining unit and 21% are positioned at managerial and 1% executive level. The wage settlement agreement has a significant impact on employee benefit costs because of the high proportion of bargaining unit staff. The salary adjustments for FY2023 were as follows:

- **Bargaining Unit Employees**

Eskom implemented a 1.5% increase as from 1 July 2021 - 30 June 2022. The salary increases negotiations for bargaining unit employees for FY2021 resulted in a dispute being declared with the CCMA. Eskom implemented a 1.5% annual increase subject to the outcome of the CCMA arbitration process. The arbitration process concluded, and the CCMA issued an arbitration award dated 27 September 2022 for an additional 1.5% annual increase, effective from 1 July 2021 (backdated). From 1 July 2022 to 30 June 2023 all bargaining unit employees received an increase in basic salary of 7% across the board, effective 1 July 2022. The normal Eskom remuneration principles applied to this.

- **Managerial Level Employees (Non-Bargaining)**

Eskom implemented 0% adjustment from 1 October 2021 - 30 September 2022. This was in line with the National Treasury Equity Conditions linked to the Special Appropriation Act of 2019. However, in recognition of years of sacrifice for no or below-inflation increases Eskom implemented a 7% salary increase for managerial employees with effect from 1 October 2022 – 30 September 2023.

b) Overtime:

Overtime consists of shifts performed by staff in various plant areas and departments at power stations that are longer than their normal working hours, to ensure that the plant is managed and maintained accordingly. This includes working on Saturdays, Sundays, and Public Holidays. The main drivers behind the overtime costs for FY2023 are:

- Overtime due to unit trips and outages (routine and unplanned maintenance), to bring the units back on time as per schedule.
- Multiple plant breakdown repairs, Units Light-ups support, commissioning activities and emergency callouts
- Overtime for security personnel for guarding the station during Outages or when unit(s) is offline, to perform security inspections and patrols in the units.

- Overtime due to Commercial staff serving meals to shift workers over the weekends and public holidays.
- The warehouse employees operating on standby, weekends and public holidays to issue out spares to the end users.
- Standby callouts during unit trips and planned inspections during weekend opportunity outages that require engineering verifications.

c) Post-Retirement Medical Benefits:

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

d) Leave:

Leave pay is related to monthly provision for leave provisions (annual leave, occasional or service leave) based on leave accumulated by employees. Provisions for leave pay are split between annual leave and service or occasional leave.

e) Pension Benefits:

The Eskom contribution to the pension fund.

f) Bonus Cost/Rewards

- **Annual Bonus:**

This is essentially a "thirteenth cheque" and **<u>not</u>** an annual bonus that is linked to operational and financial performance of the organisation but rather forms part of the employment contract in that staff are allowed to flex a portion of their salary package into a "thirteenth cheque" paid in November. Managerial employees can choose to spread the payment over the course of the year instead of all being paid in November. It forms part of the employees' conditions of services and is part of their normal package.

- **Awards Cost:**

Expense incurred payments of chairman's/ management/ long service awards. Chairman's awards were not held in FY2023.

g) Allowances:

The allowances are driven by:

- **Vehicle allowances**: The car allowances granted to Eskom employees that are required to travel
- **Housing allowances**: The housing allowance or rental subsidy granted to Eskom employees.
- **Other allowances**: The other allowances paid to employees where allowance cannot be allocated to a specific account (e.g. settling-in allowances).
- **Shift allowances:** The allowance paid to employees who work 2 and 3 shift cycles.
- **Camping allowances:** The camping allowances given to employees where employees are required to be on the field.
- **Allowances during training:** The allowance granted to employees while on training.
- **Cellular phone allowances:** The cell phone allowances granted to Eskom employees who are required to be reached at all times.

h) Employer contributions

Eskom contribution to the various medical aid schemes. Other contributions include benefit schemes such as for legislative compliance (eg unemployment insurance) and others such as death benefit funds.

- **Skills Levies**

  Skills Development Levy: is a levy that employers contribute for skills development of employees, calculated at 1% of the total salary paid to employees.

  Skills development grant received: Grants received from the Sector Education and Training authority (SETA), including skills levy rebates.

- **Bursaries and Scholarships**

  Amounts paid to universities and Technikons for further study on behalf of non-Eskom employees and children of Eskom employees.

- **Separation/ Severance cost**

  The separation packages given to employees where those employees voluntarily leave Eskom's employ.

i) Training and Development: for attending external training at a university or other training institution (including training material). Examples include the training for power station managers provided by a professional firm.

j) Temporary and contract staff costs:

- **Salary and wages non-permanent staff:** The salary relating to non-permanent staff (temporary staff), including vacation students and FTE's.
- **Non payroll temporary staff:** Labour cost of persons employed as temporary staff not paid via payroll with other permanent employees.

k) Other staff costs:

- **Professional institution fees**: Subscriptions paid to professional bodies on behalf of employees eg. SAICA, CIMA.
- **Contingency cost allowance**: Contingency cost allowance given to employee.
- **Workmen's compensation** paid to the SA Labour department in terms of the Compensation for Occupational Injuries and Diseases Act.
- **Relocation and settling-in**: paid for relocation and settling-in expenses. Includes transportation of employee's possessions as a result of employment or transfer of the employee.
- **Recruiting expenses (including advertising):** paid to external recruiting agents including employment agency fees, advertising costs and recruiting expenses. Advertising relates only to placement of an advert which sets out the job description and requirements for a prospective employee.

l) Capitalised to property plant & Equipment

- **Capitalisation of manpower project costs:** The capitalisation of the manpower costs included within the capital overhead pool to the work under construction.

m) Employee Benefit Recovery postings

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

- Projects direct labour costs
- Engineering direct labour costs
- Outage management direct labour costs
- PTM direct labour costs
- Eskom academy of learning support - direct training labour costs
- Eskom real estate support - direct labour costs

- Commercial support - direct labour costs
- Finance support - direct FBP labour costs
- SS - revenue management support labour costs
- Group IT support - direct labour costs

18.3.2 Transmission Employee Benefit Cost

Table 65: Transmission Employee Benefits

Transmission Employee Costs	Application FY2023	Actual FY2023	Variance
Employee Expenses (R'm)	2 708	2 699	(9)
Employee number	3 154	3 077	(77)

The NERSA MYPD5 Reasons for Decision (FY2023) did not apportion its decision per licensee. In the absence of such apportionment, the base of the RCA motivation is a comparison between the actual expenditure and costs that were included in the revenue application. Transmission's MYPD5 revenue application acknowledged the need for fundamental operational changes to provide sustainable electricity supply to all South Africans. It furthermore states that efficiency opportunities are pursued to ensure that the employee number increase is contained utilizing natural attrition and voluntary separation options with an intention to drive internal efficiencies, increase productivity and lower operating costs. This will be done as Eskom implements the Department of Public Enterprises (DPE) roadmap on functional and legal unbundling.

Table 66: Detailed Transmission Employee Benefit Costs

Transmission: Employee Costs (Rm)	Application FY2023	Actual FY2023	Variance
Salaries	1 918	1 980	62
Overtime	67	66	(1)
Post-employment Medical Benefits	34	28	(6)
Leave	90	111	21
Pension Benefits	227	236	9
Bonus Cost/Rewards	111	125	15
Allowances	246	239	(7)
Employer Contributions	196	162	(33)
Direct Costs of Employment	**2 889**	**2 948**	**59**
Training and Development	29	9	(19)
Temporary and Contract Staff Costs	29	12	(17)
Other Staff Cost	82	75	(7)
Gross Employee Benefit Expense	**3 029**	**3 044**	**16**
Employee Benefit Recovery postings	6	31	26
Capitalised to Property, Plant and Equipment	(327)	(377)	(50)
Net Employee Benefit Expense	**2 708**	**2 699**	**(9)**

Direct cost of employment is R59 million higher than in the application and is primarily due to salaries and salary related costs arising from annual benefits adjustments when compared to the application.

- The **salaries** variance of R62 million can be split into the following:
  - Unfavourable price variance of R108 million mainly due to 7% percent salary adjustments for all Eskom employees excluding the senior management level employees. This was based on the bargaining process agreement reached between Eskom and its recognised trade unions.
  - favourable volume variance is R47 million mainly owing to 2% less staff than the MYPD5 application in FY2023.
- **Leave pay provision** - The main driver of leave pay is the leave encashment that employees exercise in lieu of occasional/service leave that they have accumulated. It is linked to salary adjustment.
- The variance in **allowances and employer contributions** are structuring of salaries and medical aid options/packages that employees take.
- **Bonus Costs -** Transmission incurred R125 million under the line item termed “annual bonus cost”, the “bonus” is not linked to operational and financial performance of the organisation but rather forms part of the employment contract which employees are allowed to flex a portion of their salary as a “13th cheque”. Transmission’s MYPD 5 revenue application (FY2023 - R111 million) did not include any provision for performance incentive bonus payments.
- **Training, contract staff and other staff costs** are lower than the application due to ongoing efforts by Eskom to explore costs efficiencies wherever possible resulted in limitation of external training opportunities. The post Covid-19 work environment has necessitated a transition towards having training interventions being conducted via online platforms and employees having virtual operational meetings. This has contributed to reduction in training costs and contingency travel allowances claims.
- The increase in capex expenditure resulted in more work executed in the capital programme environment therefore the higher **capitalisation of employee benefit cost**.

18.3.2.1 Employee Benefit Cost drivers

Table 67: Transmission employee numbers

Tx Employee numbers	Application FY2023		Actual FY2023	
Senior Management	56	2%	54	2%
Middle Management & Professional	887	28%	997	32%
Bargaining unit	2 211	70%	2 026	66%
Total Employees	**3 154**		**3 077**	

Approximately two thirds of Transmission licensee staff complement belongs to the bargaining unit and remainder are positioned at managerial and executive level as can be seen in the table above. The wage settlement agreement has a significant impact on the employee benefit costs because of the high proportion of bargaining unit employees. Employee benefit costs are influenced by the following factors:

a) **Staff complement -** Staff turnover is limited to natural attrition of employees (resignations, retirements, death), and a few external appointments.

b) **Employee benefit increases -**. Eskom implemented 7% salary adjustments in FY2023 for bargaining and non-bargaining employees excluding senior management. In addition to salary adjustment, other annual CPI adjustments on housing allowance for bargaining unit employees.

18.3.3 Distribution Employee Benefit Cost

Table 68: Distribution Employee Benefit cost and employee numbers

Employee benefit cost &	Application FY2023	Decision FY2023	Actual FY2023	RCA FY2023
Employee benefit cost (Rm)	11 991	Eskom level	11 606	(385)
Employee number	17 422		15 863	(1 559)

The Employee benefit cost has a variance of R385m for the benefit of the consumer when compared to the revenue application (since decision was made at Eskom level) and the employee number is 1 559 lower.

Table 69: Distribution Employee Benefit Cost

Employee benefit cost (R'm)	Application FY2023	Decision FY2023	Actual FY2023	RCA FY2023
Salaries	7 311	Decision at an Eskom level	7 249	(62)
Overtime	464		621	157
Post-employment medical benefits	141		199	58
Leave	350		366	16
Annual bonus	546		577	31
Pension benefits	940		935	(5)
Allowances	1 392		1 190	(202)
Employer contributions	1 056		864	(192)
Direct costs of employment	**12 199**		**12 001**	**(198)**
Training and development	116		23	(93)
Temporary and contract staff costs	338		5	(333)
Other Staff cost	347		279	(68)
Recovery postings	21		(24)	(45)
Indirect costs of employment	**822**		**283**	**(539)**
Employee benefit cost prior to capitalisation	**13 021**		**12 285**	**(737)**
Capitalised to property, plant and equipment	(1 030)		(679)	351
Total employee benefit cost	**11 991**		**11 606**	**(385)**

NB: The annual bonus refers to the “Thirteenth cheque”. This is **not** an annual bonus that is linked to operational and financial performance of the organisation but rather forms part of the employment contract.

18.3.3.1 Actual expenditure

Distribution continues with efforts to optimize employee numbers by ensuring its employee benefit costs are reasonable whilst driving productivity improvements in operations. The intention is to retain critical and core skills for the sustainability of operations.

The network is currently operating under challenging conditions due to the age of the network and ongoing support to the electrification programme. It is essential for the Distribution licensee to build capacity, with motivated and high-performing work teams to respond to current and future needs. The sustainability of the Distribution business is dependent on its ability to create, develop and maintain a reliable and flexible network to meet customer demands.

Distribution employees are engaged in providing a service to the customer, operating and maintaining the electrical network and associated infrastructure. This is to ensure compliance to the Licensee conditions of supply whilst providing sustainable supply of electricity to all South Africans.

The variance in Employee Benefits can be explained as follows:

- The direct cost of employment was lower than the application. The major contributors were in allowances and employer contributions because of a lower employee numbers. Salary increases awarded to the bargaining unit employees were higher than the application however the variance in salaries was still lower than the application. This is due to an offset in the lower employee numbers which tempered the increases received by bargaining unit employees. Overtime costs were largely affected by the reinstatement of conditions of services which resulted in higher costs.
- The favorable variance in indirect cost of employment was due to lower training cost and contractors or temporary staff.
- Capitalisation of employee benefit cost is lower than the application by R351m. The variance was a result of the lower capital expenditure. The total capital expenditure was R4bn less than the application therefore less work was required, resulting in a reduced capitalised amount.

18.3.3.2 Distribution Employee benefit cost drivers

- **Sustaining network performance and operations**

Distribution intends to maintain network performance through disciplined execution by managing the duration of outages and frequency of network interruptions experienced by customer. A technically skilled workforce is required to maintain the electrical network infrastructure from a planned and corrective maintenance perspective in compliance with electrical standards, safety and regulatory requirements. It is imperative that these employees have specialised competencies, authorised in accordance with the applicable legislation and regulation to operate the network of various voltage levels to ensure safe operations.

- **Electrification growth**

The electrification programme contributes significantly to the growth in customer number. The growth in electrification emanates from connecting additional customers in deep rural areas to support the government electrification programme towards universal access in proclaimed areas. This growth in electrification customers and network increase the maintenance requirements and customer support, thus requiring the current employee base to respond to increased customer service level expectations in terms of duration of outages and frequency of interruptions.

- **Employee safety in operations**

The safety of employees remains a key priority for Eskom. It is therefore imperative that adequate and skilled resources are directed to operations to avert injuries and fatalities of employees whilst adhering to all legislative requirements.

- **Development and training of employees for operations**

The Licensee continues to develop and train its workforce for normal business operations, emerging technologies and new business opportunities. Employees are required to be multi-skilled to operate the network and provide a service to the customer. There is mandatory legislative training required for employees to operate the network.

- **Customer operations**

Customer service is the interface between Eskom and the customer to ensure an optimal and satisfactory customer experience. This service is provided by Key customer executives, hubs and call centres to service large power users and all other customer categories. The growth in customer numbers will require adequate resourcing in the Contact Centre environment for customer contact management for inbound and outbound interactions.

- **Remuneration of employees**

The employee costs are also a function of CPI and the final negotiated wage settlement with trade unions. The Distribution licensee employees are mainly operational level staff (91% of the total complement) therefore the negotiated salary increases, which were higher than inflation, have a significant impact on employee cost.

18.4 Maintenance Costs

Table 70: Summary of Generation, Transmission and Distribution Maintenance costs

Maintenance costs (R'm)	Decision FY2023	Actual FY2023	Variance
Generation	14 029	16 581	2 552
Transmission	982	1 087	105
Distribution	5 184	4 378	(806)
Total	**20 195**	**22 045**	**1 850**

18.4.1 Generation Maintenance Costs

Table 71: Generation Maintenance Costs

Gx Maintenance (R'm)	Decision FY2023	Actuals FY2023	RCA FY2023
Generation Maintenance Costs	14 029	16 581	2 552

18.4.1.1 Generation Life Cycle Management Process

Generating plants require a large initial investment and significant further expenditure to continue operations over its intended life. Good asset management practices refer to having a plant strategy to manage the assets over their full life cycle that directs the activities that drive the investment needs.

Eskom Generation has committed to develop and regularly update detailed life cycle plans for all business units which reflect the required refurbishment and replacement activities on all relevant plant systems till the end of plant life ie. the Life of Plant Plan (LOPP). In addition, the plan shall reflect those modifications and improvements that may be required to address any changes in plant condition, operation, capacity, obsolescence, legislative requirements (inclusive of safety, health and environment), primary energy supply or operational lifespan.

This Life Cycle Management Process is a detailed and robust process with the aim of carrying out a structured and defendable basis ***for the allocation of limited funds*** to the Power Stations to enable them to deliver sustainable performance.

18.4.1.2 The Root Cause of Challenges Faced

Even with an established maintenance management process in place, Eskom Generation's coal fired fleet currently faces the challenge of unreliable and unpredictable performance. This in effect reduces the national generating capacity available to meet the demand for electricity. Whilst this contributes to load shedding, it is not the primary reason for the levels of loadshedding experienced in the country at present or from 2008 onwards. This is illustrated by the fact that in 2008 (and up to 2012) the Eskom generation fleet was operating at performance levels (both for EAF as well as EUF) in line with or exceeding the benchmark performance levels of the European-based VGB association of electricity plant operators representing many hundreds of generating units – yet there was frequent loadshedding from 2008 onwards. Clearly it was not due to poor plant performance.
There are three important reasons for the inability to meet the country's electricity demand consistently that have led to loadshedding and high open-cycle gas turbine (OCGT) usage:

a. The first is inadequate installed capacity nationwide – which is mainly due to the IPP programmes not materialising as planned.

b. The second is the above-mentioned performance of the Generation coal fleet, evidenced by the low energy availability factor (EAF). The second is in fact a consequence of the first, with inadequate national capacity occurring from around 2003 onwards and have not yet been restored to acceptable levels. The inadequate national generating capacity inevitably results in the existing fleet having to create 'virtual capacity' in order to close the supply-demand gap. This it started doing from 2003 onwards by initially increasing the EUF levels, and when additional 'virtual capacity' was required from 2008 onwards, it was created by deferring maintenance outages. Predictably and inevitably, this eventually results in reducing technical performance levels, which started manifesting from 2012 onwards, creating a vicious circle of further reducing the national generating capacity thus compelling a further increase in EUF and further deferral of maintenance outages.

c. A third major factor started increasingly manifesting from approximately 2014 onwards with the MYPD3 revenue cycle, namely insufficient funds to perform the required maintenance due to the sub-cost-reflective revenues.

18.4.1.3 Categorisation of Types of Maintenance

Maintenance is either preventative or reactive in nature.

Generation's Maintenance Opex is split into four main categories:

a) Outage R&E (Revenue & Expenditure),
b) Technical Plan Projects R&E (Revenue & Expenditure),
c) Routine Maintenance Cost;
d) Breakdown Maintenance Cost

It is important to note that this *does not* represent the Total Maintenance Cost ie. it excludes the capitalised portion which is categorised as Outage Capex and Tech Plan Capex. All of these maintenance projects/initiatives are aligned to the LOPP.

a. Routine maintenance

This refers to maintenance services undertaken during normal operation of the plant. It covers maintenance which happens regularly and continuously and is not dependent on lengthy unit shutdowns. That is, oil changes, routine and minor adjustments and servicing, all mill maintenance, boiler tube leaks, maintenance during forced outages (UCLF) and short planned outages (< 14 days).

b. Breakdown maintenance

Breakdown maintenance represents restoration of the plant which unexpectedly fails. Such failures require immediate attention as failure to repair will lead to loss of production. These costs are interrogated, and the objective is to limit them through inspections and analysis of trends. This expenditure is mandatory to ensure continuity of supply.

c. Technical plan

A detailed consolidated list of projects extracted from the first five years of the prioritised LOPP which meet certain funding and execution criteria as determined by Portfolio Management. This includes Capital and Non-Capital (R&E) projects.

d. Outage maintenance

Outage maintenance is planned maintenance and is carried out on identified baskets of plant systems and are aimed to last at least to the next planned outage without failing. It entails servicing and repairing of plant components that cannot be repaired while the plant is in operation. In addition to ensuring that plant health is maintained, outage maintenance ensures that the statutory inspections and repairs are executed.

The scope to be executed in an outage is challenged by experts from different disciplines to test their justification and the amount of money allocated to execute them. Assessments are also done on a continuous basis to assess if the duration between the outages can be increased in order to potentially limit the frequency of expenditure on unit outages.

Outages are therefore necessary to ensure continuity of supply and the cost containment is effected through ensuring that activities which are executed are necessary and priced at the correct level. While certain activities may be planned to be executed, prudence dictates that if on inspection it is found that the components are still healthy to run until the next outage such components are not replaced.

Table 72: Generation Maintenance costs per power station (Actuals vs Decision)

Gx Maintenance Cost per Power Station (R'm)	Decision FY2023	Actuals FY2023	RCA FY2023
Acacia		1	
Ankerlig		24	
Arnot		805	
Camden		908	
Capital Project Execution - Gx Projects		111	
Coal 1		13	
Drakensberg		51	
Duvha		875	
Gariep		9	
Gourikwa		22	
Grootvlei		475	
Gx DE Office		266	
Hendrina		806	
Ingula		103	
Kendal		723	
Koeberg		1 739	
Komati		158	
Kriel		1 327	
Kusile		1 357	
Lethabo		938	
Majuba		1 110	
Matimba		670	
Matla		1 713	
Medupi		1 512	
Palmiet		27	
Peaking - Durbanville		1	
Port Rex		15	
Renewables		49	
Tutuka		773	
Vanderkloof		2	
Grand Total	**14029**	**16 581**	**2 552**

18.4.1.4 Generation's Maintenance Cost in perspective: Generation Maintenance Costs Benchmarking

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

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

Figure 20: International approach of measuring the efficiency of a utility's maintenance spend

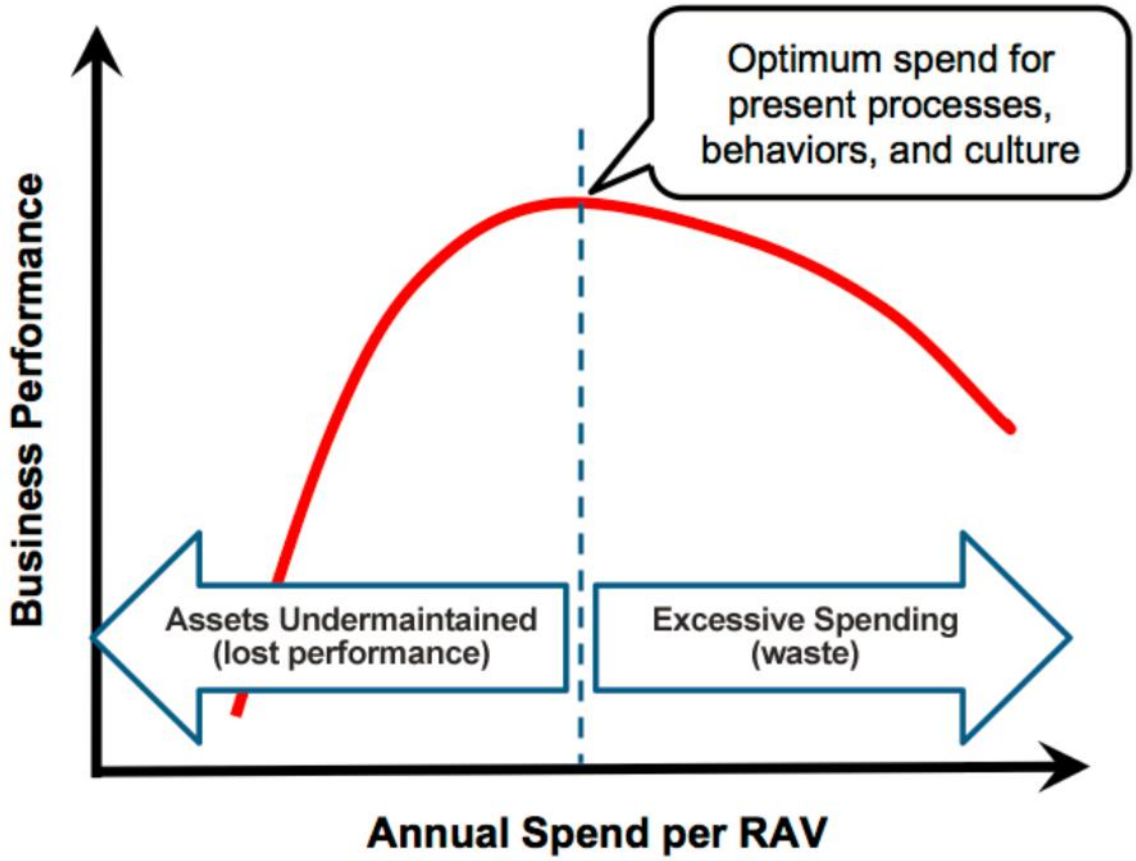
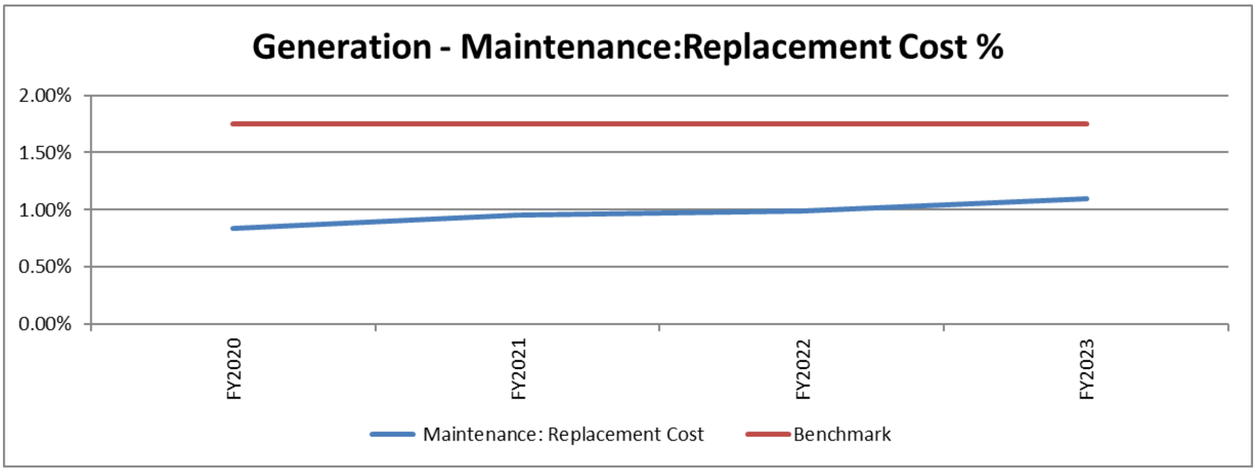


Figure 21: Generation Maintenance Replacement Cost (%)



How does Generation compare relative to this benchmark?

On this benchmark Generation's maintenance spend is below the lower boundary. This benchmark serves to further highlight the reasonability of Generation's Maintenance spend from a monetary perspective.

18.4.1.5 Conclusion on Generation maintenance

Maintenance activities on the plant are carried out to ensure that the plant is available to meet demand, to the extent that system space and funding is available to do so. Continuous assessments are made (taking into consideration the constrained system space and funding) to determine which plant components need to be maintained and to what extent. The monetary targets are set to ensure that expenditure is incurred in a systematic and controlled manner. The amount of expenditure is controlled by ensuring the scope of work is contained through inspections and continuous improvement. The costs are also contained by ensuring that contracts are placed at market related prices.

18.4.2 Transmission Maintenance cost

Table 73: Transmission maintenance variances

Tx Maintenance costs (R'm)	Decision FY2023	Actual FY2023	Variance
Servitude Maintenance	171	191	21
Line Maintenance	191	236	45
Primary Plant Maintenance	207	221	14
Secondary Plant Maintenance	57	47	-10
Equipment & Spares	34	17	-17
Rotek (Transformer & Logistics)	303	344	41
Other	19	30	11
Total	**982**	**1 087**	**105**

Maintenance variance of R105 million compared to the decision of R982 million (11% variance) mainly due to variance in line, servitude and transformer maintenance. Maintenance expenditure has increased by 30% compared to FY2022. Maintenance contract have been placed and finalised and major catch-up maintenance had to done in lieu of previous year inability to conduct the required maintenance due to delay in the conclusion of servitude maintenance contracts and service contracts, issuing of enquiries and tender evaluations.

Notwithstanding the need to embark and promote operational cost efficiencies, a general increase in maintenance expenditure is required:

- To sustain the aging plant which poses a risk to the system,
- To undertake network recovery work following major incidents or plant failures
- To carry out maintenance or repair activities that do not form part of routine maintenance plans such as repairing of major transformer oil leaks and replacement or repair of corroded components.

18.4.3 Distribution Maintenance cost

Table 74: Distribution Maintenance cost

Dx Maintenance Cost (R'm)	Decision FY2023	Actual FY2023	RCA FY2023
Planned	2 592	1 914	(678)
Unplanned	2 592	2 464	(128)
Total Maintenance	**5 184**	**4 378**	**(806)**

Distribution maintenance costs have a variance in favour of the consumer of R806m when compared to NERSA's decision. The execution of maintenance was impacted by timeous conclusion of contracts and the availability of materials, as well as the cancellation of outages due to load shedding, theft, vandalism, and the use of operational staff (incl. control centres) to implement load shedding and restoration of supply. Severe weather patterns across the country have also adversely impacted the occurrence off maintenance.

18.4.3.1 Key drivers for the Distribution maintenance expenditure include:

- **Network performance**

To ensure adequate maintenance is completed for the uninterrupted supply of electricity to the customer and security revenue streams. Adequate maintenance spend will ensure that the network performs as per the design base with minimal technical losses.

- **Quality of service to the customer**

Adequate maintenance affords the ability to deliver energy to customer on demand at the right voltages level as defined in the National Regulated Standards

- **Growing network and customer base**

The network infrastructure grows with an increase in the customer base of more than 100 000 customers annually, which increases the maintenance requirements in both the preventative and corrective (fault) environments.

- **Sustainability of network infra-structure**

The network infra-structure is aging and with limited capital investment leading to potential sub-optimal performance and sustainability of network.

- **Environmental and safety consideration**

To ensure safe operations of network with a minimum impact to the environment

18.5 Other Operating Costs

Table 75: Summary of Other Operating Costs

Operating expenditure (R'm)	Decision FY2023	Actual FY2023	Variance
Generation	Eskom level	11 939	Eskom level
Transmission		901	
Distribution		4 481	
SAE		3	
IDM		41	
Total	**11 996**	**17 365**	**5 369**

18.5.1 Generation Other Opex

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

Table 76: Generation Other Opex

Gx Total Other Opex (R'm)	Actuals FY2023
Contractor Costs	399
Decommissioning Expenses	-705
Environmental expenses	178
Internal Electricity Revenue Consumption	724
Materials Expense	1 566
Net Insurance Expense	3 322
Office and Site Operation Costs	1 837
Operating Lease, Consulting &Travel	710
Other General Expenses	5 903

Gx Total Other Opex (R'm)	Actuals FY2023
Recovery Postings	-582
Secondary Account Capitalisations	-1414
Generation Total Other Opex	**11 939**
**** RCA Adjustment***	***(2852)***
Generation Total Other Opex for RCA Purposes	**9087**

Note: RCA Adjustment relates to Kusile overpayment and inventory which could not be accounted for after physical stock counts and does not form part of the RCA Claim as it is deemed to be imprudent.

18.5.1.1 Contractor Costs

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

18.5.1.2 Decommissioning Expenses

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

If the related asset is measured using the cost model:

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

18.5.1.3 Environmental Expenses

This relates to costs incurred in cleaning up the environment, waste management and removal, emptying and removal of bins from site and monthly analysis of water and effluent.

18.5.1.4 Internal Electricity Revenue Consumption

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

18.5.1.5 Materials Expense

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

18.5.1.6 Net Insurance Expense

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

Factors that influence the insurance premium:

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

Maintenance and asset renewal are good measures to treat the risk of failures due to ageing plant. The net Insurance expense could increase considering the aging generation fleet and maintenance activities that are postponed as these increases plant risks.

18.5.1.7 Office and Site Operations Costs

This constitutes mainly of the following components:

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

18.5.1.8 Operating Lease, Consulting and Travel Costs

This consists of the following:

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

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

  - Capital Depreciation Costs;
  - Maintenance Cost;
  - Insurance;
  - Management and administration fees.
  - Operating Lease Expenses
  - Consultancy Fees

18.5.1.9 Other General Expenses

Other General Expenses include the following components:

- Production plant service cost
- Servitude service contractor
- Facility service costs
- Equipment spares and repairs service contractor
- Legal fees
- Printing, stationery and office
- Telephones & cellphones
- Facilities cost
- Facilities cost - water and electricity
- Marketing expenses
- Insurance repairs
- Low value assets written off on purchase

- Sundry other expenses

18.5.2 Transmission Other Opex

Table 77: Transmission Other operating expenses

Tx Other Operating costs (R'm)	Application FY2023	Decision FY2023	Actual FY2023
Insurance Premiums	269		198
Security Expenses	152		216
Telecommunications	96		68
IT Expenses	92		41
Travel & Fleet Expenses	94		69
Consulting and Legal Costs	48		52
Facilities	53		29
Leases	30		20
Internal Electricity Costs	26		31
Other	307		187
Operating costs before Abnormal costs and Recoveries	**1 169**	**Eskom Level**	**910**
Abnormal costs	**-**		364
Recovery by Service Functions (Telecom & Aviation)	(420)		(373)
Total Operating costs including Abnormal costs and Recoveries	**750**	**Eskom Level**	**901**

Transmission continues to embark and promote operational cost efficiencies. Other operating costs are fixed in nature and therefore increases are due to inflation. In FY2023 operating costs (excluding abnormal costs) were 28% less than MYPD 5 application largely owing to travel and fleet expenses as well as insurance and telecommunication costs. Furthermore, R364 million of the total other operational expenses is classified as costs not incurred in the normal course of business operations.

The total other operating expenses of R901 million (including abnormal costs) are attributable to the following items:

- **Insurance Premiums** - ESCAP insurance premiums are mainly based on the size of the declared assets. The proportion of Transmission's declared assets against the overall Eskom asset base resulted in a 9% decrease in the FY2023 insurance premium compared to FY2022.

- **Security** – Most of Transmission's substations are in remote areas where security reaction units are not available therefore security guards and other technological systems are employed to mitigate increased risks in copper theft, vandalism of facilities and to preserve the integrity of assets and continuity of supply.

Table 78: Transmission Security Incidents

Type of Security Incident	Number of Security Incidents	
	FY2023	FY2022
Theft of Cables, Batteries and Transformers	171	145
Tower member theft	21	23
Malicious Damage to Property	79	63
Armed Robbery	40	40
Attempted theft, Common theft, and Housebreaking	104	106
Other	33	28
Total	**448**	**405**

Transmission has experienced an increase in the number and severity of security incidents (as illustrated in the table above) necessitating an increase in security expenses to safeguard our assets and employees. To address the severity of security incidents within the Transmission, a Security Action Plan was developed, and it comprises of key deliverables that are aimed in dealing with identified security threats within the Division. The key objectives of this action plan include the following:

- Conducting Security Threat Assessments & Security Plans within the various Business Units and reviewing of the current security strategy
- Development of the Transmission Security Nerve Centre (TSNC)
- Implementation of the Intelligence and Investigation Contract at key high risk sites to ensure intelligence gathering, arrests, convictions, syndicates, and scrap dealers profiling.
- Rolling-out of the Bernina-Hera security technology standard to the high-risk substations and radio sites across Transmission to ensure the Deterrence, Detection, Delay & Response to criminal incidents.

In addition to the Security Action Plan the division is also involved in the security quick-wins project that explores the technology-based security solutions by installing the all-in-one solution motion sensors that illuminates light and audible alarms when triggered. As a result of its success more units have been procured and they will be installed at selected high-risk substations.

- **Telecommunication costs** are primarily due to the following services:
  - Operational SCADA information for circuit visibility / controllability in the control room.
  - Control room communication.
  - Enabling remote interrogation of digital fault recorders.
  - Enabling remote downloading of revenue meters at Transmission boundaries.

- Enabling communication with Wide Area Monitoring devices

- **Information Technology (IT) expenses** are mostly driven by the number of users and the number of applications used. Charges associated with infrastructure services; end user computing and help desk services are based on the monthly quantities of the various service items included in the contracts. Software annual licencing and support costs are charged proportionally based on the number of personal computer users.

- **Consulting costs** have slightly increased compared to the revenue application forecasts. It is Eskom's policy to appoint external service providers only in circumstances where such skills are not available within the organisation or where it prudent to elicit advice/services of an independent body. Consulting costs includes.

  - legal services and support that are required for servitude acquisition negotiations and disputes that arise with the landowners as well as registrations of acquired servitude.

  - Independent professional service providers to undertake certain in acquiring property/servitude rights. This includes Geotech studies, town planning assessments, visual/social impact assessments, property valuation and land surveying.

  - Designing services fees to assist with engineering designs.

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

- **Fleet & Travel** – this includes both the local and international business travel undertaken by employees for the operational course of business as well as to attend training and meetings on behalf of Eskom. There has been a considerable decrease in travel expenses due to having high number of business engagements and meetings being conducted via virtual platforms.

  Furthermore, the decrease in expenditure is due to the classification of most **fleet costs** as part of maintenance expenses. Transmission vehicle fleet is almost exclusively used by employees to access different sites for plant maintenance and repairs.

- **Facilities** – these costs are to service and maintain buildings and facilities. The costs incurred are for rates and taxes, municipal services, maintenance, repairs, cleaning services and related items. The transfer of properties from Eskom Real Estate to line division has contributed to increase of facility related costs such as municipal rates & taxes.

- **Leases**: this is primarily for the rental of office space, aircraft hangars and storage areas where Eskom does not own sufficient facilities as well as for telecommunication infrastructure site sharing..
- **Other**: The other expense includes impairments, Telecom plant maintenance and other sundry expenses.
- **Recoveries by Service functions**: Eskom Aviation and Eskom Telecommunication provide services to Transmission and other divisions within Eskom.
- **Abnormal Costs**: These are costs that are not incurred in the normal course of business operation. The R364 million abnormal expenditure relates to expensing of projects costs. Eskom policy considers costs incurred in the concept and definition phases as research, requiring that they be expensed. A review of the assets under construction identified concept and definition costs included in the capital balance. The R364 million abnormal entry relates to correction in classification.

18.5.3 Distribution Other Opex

Table 79: Distribution Other operating cost

Dx Other operating cost (R'm)	Application FY2023	Decision FY2023	Actual FY2023	RCA FY2023
Insurance	1 611	Decision at an Eskom level	1 670	59
Security cost	551		408	(143)
Information technology costs	476		426	(51)
Fleet cost	52		366	314
Facilities cost	635		448	(187)
Telecoms	147		131	(15)
Material and Contractors	342		234	(108)
Customer related:				-
Vending Commission	537		245	(292)
Customer billing related expenses	132		85	(47)
Legal Fees & Debt Collection	33		32	(1)
Wheeling cost	58		56	(2)
Bank Related Costs	22		19	(3)
Business related expenses	23		362	338
Total other cost	**4 619**	**-**	**4 481**	**(138)**

The determination for other operating cost was done on an Eskom level and not for each licensee. IDM costs were included in Distribution in the MYPD5 application; however, these costs have been disclosed separately in this RCA application. Are basing the RCA on application and not decision, since no decision at this level

18.5.3.1 Actual expenditure versus application:

The Other Operating Cost was R138m lower than the application.

The increases in the Other costs are linked to inflation and fixed in nature. Where possible the licensee has implemented cost saving measures whilst improving operating efficiencies.

Fleet costs experienced higher expenditure because of increased fuel costs as wells as increased maintenance requirements for the aging fleet. The increased occurrence of load shedding and curtailment has increased the frequency of trips and outages at sub-stations. This requires technicians to be travelling to sites more resulting in more fuel usage as well as the occurrence of maintenance.

The variance in business related expenses is largely due to the disposal of property plant and equipment. The disposals are for projects that have been written-off due to the unavailability of funds to continue the projects. This is an abnormal cost and does not occur regularly in the normal course of business.

18.5.3.2 Distribution other operating cost drivers

- **Insurance cost**

The business must ensure that there is adequate insurance cover in place to manage its increasing asset base and exposure against insurable incidents such as natural occurrence, theft, vandalism and public liability claims. The market prices for the premium are hugely driven by replacement cost of assets and past claims history. Insurance covers risk beyond the maximum tolerance levels for the business.

- **Security cost**

Many of the Distribution sites are designated national key points, which in terms of legislation require these assets and people to be safely guarded. There has been an increase in theft and vandalism of equipment which warrants the need to safeguard assets for continuity of operations. Security related activities are preventative in nature to safeguard assets, property and employees.

- **Information technology costs**

Information management systems are key to the current and future business operations to support improvement in efficiency, productivity and decision making. The vastness and complexity of network infra-structure requires a number of integrated management systems for network management, outages, dispatching and customer interface and interaction. The information systems enable optimal and efficient network operating, optimal customer billing and revenue collection. The changing customer needs necessitate investment in digital platforms which require continued maintenance to support delivery of the desired customer experience and service delivery.

- **Fleet and travel cost**

The Distribution network infrastructure footprint is across South Africa mainly in deep rural areas. Employees are required to extensively travel to provide a service to all customers. This involves operating, maintaining and repairing networks to comply with regulatory and service standards. Key to the cost is employee recoveries of travel costs for business related activities and associated subsistence allowances. The employees are reimbursed at the SARS travel rates and the Eskom policy aligned to National Treasury Directive on cost containment.

- **Facility cost**

The geographical customer spread across the country, accessibility, convenience to the customer and the business value proposition to meet customer expectations required the establishment and maintenance of customer network centres, hubs and local offices in close proximity to the customer locations. These properties are either owned or leased and the business carries all associated service costs. The driver of the facility cost relates to rentals, water, electricity, rates, taxes and maintenance.

- **Vending commission**

The prepaid customer base is served through a network of vending agents located in proximity through various platforms for ease of access for the customer. Vending commissions are costs paid to the agents that sell electricity on behalf of Eskom.

- **Customer billing and meter reading expenses**

Billed customer meters are read in intervals through meter reading agents to ensure accurate and timeous billing for energy consumed. The meter reading agents are compensated for the actual number of customer meters read at a predetermined rate. The business also incurs costs for the generation of the customer bill and the distribution thereof.

- **Wheeling cost**

Wheeling cost is the transportation of electric energy from within an electrical grid to an electrical load outside the grid boundaries.

18.5.3.3 Arrear Debt

Table 80: Arrear Debt

Arrear debt calculation	Decision FY2023	Actual FY2023	RCA FY2023
Electricity revenue	250 452	273 276	
Less: Revenue from international customers	8 799	10 587	
Less: Load shedding (1605 GWh @ 133.64 average c/kWh)	-	19 740	
Revenue from local customers	241 653	242 949	
Arrear debt	-	-	-
Arrear debt allowed in FY2023 decision expressed as a % of allowed revenue from local customers	*0.00%*		
SAE arrear debt	-	**178**	**178**
Total RCA claim	-	**178**	**178**

Eskom does not include the *total* arrear debt for the purposes of the RCA balance determination.

18.6 Other Income

Table 81: Summary of other income

Other Income	Decision FY2023	Actual FY2023	Variance
Generation	(427)	(2 875)	(2 448)
Transmission	(107)	(150)	(43)
Distribution	(509)	(890)	(381)
Corporate services[1]	(130)	-	130
Total	**(1 173)**	**(3 914)**	**(2 741)**

In the course of Eskom operations in FY2023, Eskom generated total other income of R3914m which is shown in the table above.

18.6.1 Generation Other Income

Table 82: Generation other income

Generation Other Income (R'm)	Decision FY2023	Actuals FY2023	RCA FY2023
Insurance Income		(2564)	
Operating lease Income		(110)	
Sale of Scrap		-	
Sundry Income		(201)	
Total Other Income	**(427)**	**(2875)**	**(2448)**

Other income for Generation was mainly due to proceeds from insurance. This was a significant variance from the NERSA decision, as illustrated in the table above.

18.6.2 Transmission Other Income

Table 83: Transmission other income variances

Tx Other Income (R'm)	Application FY2023	Decision FY2023	Actual FY2023	Variance
Insurance Proceeds			(97)	(97)
Lease income	(46)	(46)	(39)	7
Sundry Income	(61)	(61)	(13)	48
Total	**(107)**	**(107)**	**(150)**	**(43)**

Other income was R150m compared to the NERSA determination of R107m.The main reason for the variance is Insurance proceeds which are not planned as the pay-outs on insurance claims cannot be determined upfront as well less sundry income mainly due to termination of customer contracts (Broadband Infraco) owing to non-payment of long-overdue debt.

18.6.3 Distribution Other Income

Table 84: Distribution other income

Dx Other Income (R'm)	Decision FY2023	Actual FY2023	RCA FY2023
Insurance proceeds/recovery	317	677	360
Reconnection fees	-	-	-
Business sales	-	1	1
Operating Lease Income	9	11	2
Sundry income	183	200	17
Total other income	**509**	**890**	**381**

The highest contributor to other income is Insurance Proceeds/ Recoveries, resulting from more insurance work due to adverse weather conditions. Reconnection fees has been reclassified as other revenue.

18.7 Corporate services

Corporate costs are allocated to the Licensees through a corporate overhead.

Table 85: Corporate services operating cost

Operating costs (R'm)	Decision FY2023	Actual FY2023	Variance	RCA adjustments	RCA FY2023
Employee benefits	3 560	2 069	(1 491)	-	(1 491)
Maintenance		-	-	-	-
Other Opex	3 969	2 071	(1 898)	(74)	(1 971)
Arrear debt	-	-	-	-	-
Other income	(130)	(460)	(330)	-	(330)
Depreciation	292	192	(100)	-	(100)
Total	**7 691**	**3 873**	**(3 818)**	**(74)**	**(3 892)**
Add: Net finance costs	632	167	(465)	-	(465)
Total Corporate costs (incl EB costs)	**8 323**	**4 039**	**(4 284)**	**(74)**	**(4 357)**
Less: other income	(130)	-	130	-	130
Less: Corporate social investments	(102)	-	102	-	102
Total operating costs	**8 091**	**4 039**	**(4 052)**	**(74)**	**(4 125)**

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

The three major categories of NERSA's determination for the Corporate division comprised a determination of R3 560m on employee benefits, R3 969m on operating costs and depreciation of R292m, which totals to R7 821m. This, contrasted against actual spend for the year under review of 4 332m (which includes net impairments), reflects a R3 489m negative variance.

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

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

18.7.1 Corporate Employee Benefit costs

The NERSA determination on employee benefits is based on Eskom's applied application employee costs and manpower numbers i.e. there was no disallowance by NERSA. The table below iilustrates the actuals in comparison to the NERSA decision.

Table 86: Corporate Employee benefit costs

Corporate Employee costs	Decision FY2023	Actual FY2023	Variance
Employee Costs (R'm)	3 560	2 069	(1 491)
Employee number	2 868	2 242	(626)

The year-end actual employee number of 2 242 is 626 employees less than the determination. This is mainly due to the higher staff turnover and the challenge with respect to attracting suitably qualified staff.

Employee benefit cost has a variance of R1 491m for the benefit of the consumer. This is due, in part, due to the same reason stated above. Group IT has a variance (R161m) in favour of the consumer due to lower annual increases to employees, lower complement, and stricter control on overtime. Procurement & Supply Chain Management Department, Strategic functions and Group Financial controller have a variance of R119m, R307m and R365m respectively also in favour of the consumer mainly due to high staff turnover and the inability to attract suitably qualified staff. There has also been a re-determination of the pension benefit obligation with respect to the whole organisation that resulted in a variance of R484m for the benefit of Eskom. This variance has been ring-fenced at a corporate level for this financial year.

18.7.2 Depreciation

A variance in Corporate depreciation for the benefit of the consumer of R100m is primarily due to delays in capital project execution resulting in delays in transferring planned assets under construction to commercial operation.

18.7.3 Corporate Other Opex

Other operating expenses has a variance of R1 898m. The variance is due mainly to the following. Group Finance Controller has a variance of R1 424 in favour of the consumer due to a significant reduction in consulting fees and travelling. Certain short to medium term strategic initiatives being placed on hold or abandoned resulting in a variance of R198m to the favour of the consumer. Less travelling post COVID 19 as well as savings achieved through a deliberate savings drive throughout corporate services (R276m). Finance income had a variance of R445m to the favour of the consumer. Though, R700m is finance income not allocated to the other divisions in actual mode compared to the application, net off by an unfavorable R211m resulting from a pension fund actuarial revaluation.

18.7.4 Corporate Other Income

Planned income had a variance of R330m primarily due to unexpected dividends from Montraco (R160m) and management fee income from Eskom Finance Company (EFC) resulting a favourable variance of R170m.

18.7.5 Research and Development

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

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

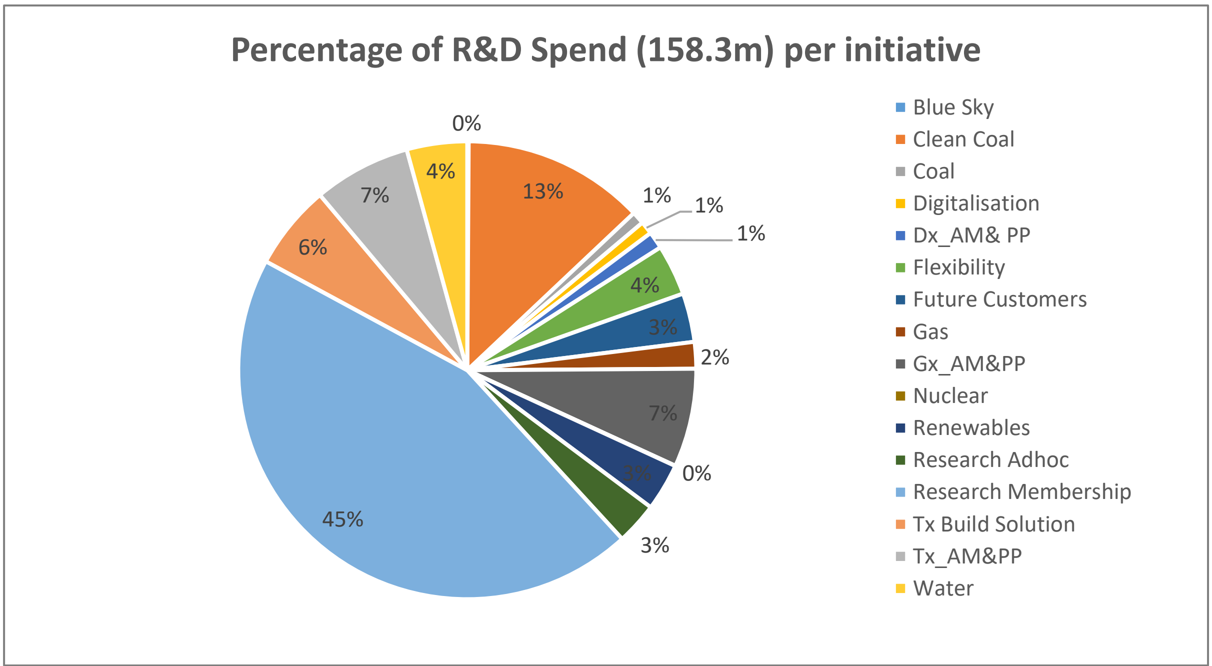
The research projects are aligned to the outcomes of deliberations between key internal, through research roadmaps for divisional business units, Generation, Transmission including Distribution and external stakeholders in various fora, including the Stakeholder Review that is convened annually. This is an engagement session in which RT&D gives feedback to industry stakeholders, most notably NERSA, about RT&D's research portfolio, and gets input from these stakeholders on what RT&D could be doing differently. This also includes shareholder's monthly and quarterly engagements for alignment of organisational research outputs and deliverables.

Table 87: Research and Development Costs

Research and Development (R'm)	Decision FY2023	Actual FY2023	Variance
Research and Development Costs	128	158	30

A greater emphasis has been placed on making sure that RT&D programmes contribute quantifiable and demonstrable value to the effectiveness and efficiency of organisations. Accordingly, the initiatives provided strategic direction. The following are the costs for FY2023.

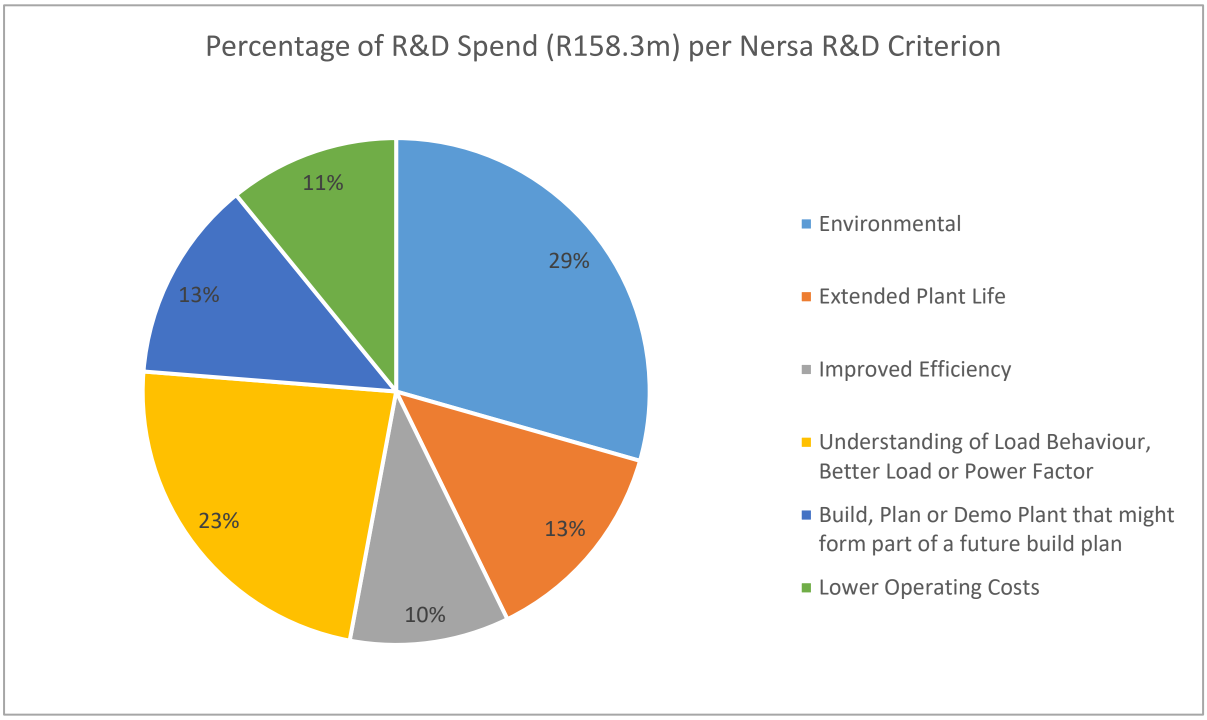
Figure 22: R&D costs per Eskom Research Initiatives



18.7.5.1 FY2023 Research & Development Costs against NERSA Criteria

The R158.3m spent on research and developments costs as per the broader NERSA criteria outlined in the MYPD Methodology is as follows:

Figure 23 : Research cost as per the NERSA Criteria



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

19 Corruption and fraud related matters

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

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

Specific initiatives to address governance failures include the following:

19.1 Restoring Eskom's reputation as a trusted corporate citizen

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

The governance focus areas of our ESG framework include various initiatives to address crime, fraud and corruption, as shown below, as well as strengthening PFMA compliance and supply chain management processes.

Developments across these areas are discussed in further detail below; however, due to the sensitive nature of these matters, not all information can be disclosed in this report.

19.2 Board investigation into the allegations by the former GCE

During an interview with eNCA in February 2023, Mr André de Ruyter made certain allegations and alluded to the involvement of Government officials in fraud and corruption, without first disclosing the information to the Board or consulting the Board on the matter. The Board could not condone Mr De Ruyter's actions and reached a mutual agreement with Mr De Ruyter to revert to the original notice period of 28 February 2023 set out in his resignation letter; he was not required to serve the balance of his notice period and was released with immediate effect on 22 February 2023.

During the interview, Mr De Ruyter publicly disclosed information on alleged fraud and corruption affecting Eskom, which has prompted the Board to initiate an investigation to determine whether there are any gaps between what is already known and under investigation by Eskom and what was alleged in the interview.

Mr André de Ruyter was asked to hand over all documentation and company assets on the day of his departure from Eskom. It is believed that an intelligence report, commissioned by Mr De Ruyter through a privately funded investigation, formed the basis for his allegations. The report was not handed over to Eskom. The Special Investigating Unit (SIU) confirmed in June 2023 that it had obtained the report from the company appointed to conduct the intelligence investigation and is reviewing the information in terms of its investigation methodology and protocols. The SIU is also investigating how the report was commissioned. An independent legal firm has been appointed to assist the Board in addressing these matters and determining any further steps required. They have obtained a copy of the report and are consolidating the findings to aid in the Board's investigation.

The allegations continue to garner extensive media coverage and the Standing Committee on Public Accounts (SCOPA) has held numerous meetings on the allegations and surrounding circumstances, inviting representation from key individuals and institutions involved. Mr De Ruyter subsequently published a book, the contents of which has been included in the list of allegations under investigation by Eskom.

The Board is taking these allegations very seriously. Should its investigation find that the allegations have merit, they will be dealt with through the appropriate channels. Eskom is cooperating with all external investigations and inquiries related to these matters.

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

As mentioned previously we have established a dedicated state capture task team which is assisted by external legal counsel. The task team has completed its review of the report of the Zondo Commission and developed an implementation plan to address the Commission's recommendations and ensure appropriate legal remedies are pursued.

The recommendations include instituting criminal charges, ensuring appropriate consequence management against employees and suppliers, pursuing director delinquency proceedings and civil recovery of financial losses suffered by Eskom.

The key focus areas of our implementation plan are consistent with these recommendations and include civil recoveries, criminal charges and consequence management for implicated suppliers, former employees and former directors identified by the Commission; an in-depth crime risk assessment; and the review of our structures, policies and procedures to support the eradication of crime, fraud and corruption going forward.

We are working with DPE, other SOCs and law enforcement agencies on various initiatives and our state capture task team is monitoring progress on the implementation of the Commissions' recommendations, including litigation instituted by the SIU through the Special Tribunal.

This report provides limited additional information since last year's report, given that much of the progress relating to the 2023 financial year was already reported on due to the delayed release of Eskom's 2022 annual financial statements and the requirement to disclose material post-year end events. Furthermore, criminal convictions and civil judgments are dependent on the justice system and this remains a lengthy process, with no substantial outcomes in these cases so far as investigations and legal proceedings are ongoing.

We continue to provide the necessary support where recommendations are being driven by another organisation or are not within Eskom's control – such as court proceedings – to ensure the successful prosecution of implicated suppliers, former employees, former directors and associated perpetrators.

19.4 Initiatives to address implicated individuals and companies

19.4.1 Consequence management of delinquent employees

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

19.4.2 Director delinquency proceedings

From a legal perspective, the most effective avenue to charge former directors and officials is through delinquency proceedings under the Companies Act, 2008. DPE is coordinating this process across all SOCs. Eskom has prepared detailed evidence packs relating to all implicated directors and has submitted the evidence relating to four former directors to the CIPC for consideration and to aid in delinquency proceedings.

19.4.3 Reporting of former delinquent directors and officials to the relevant professional body

The South African Institute of Chartered Accountants instituted disciplinary proceedings against Eskom's former Chief Financial Officer, Mr Anoj Singh, and revoked his professional membership in August 2020. Similar proceedings are being considered for other implicated individuals and we continue to work with DPE and the Department of Justice on these matters.

19.4.4 Criminal proceedings

As mentioned, we are working with law enforcement agencies to bring all criminal matters arising from the Zondo Commission report to court as soon as possible. We are monitoring progress on these matters.

19.4.5 Civil recoveries

Several civil recovery proceedings have been launched by both the SIU and Eskom. The SIU has sought to extend its mandate to include all matters raised in the report of the Zondo Commission. Our task team is monitoring civil recovery proceedings to intervene where legal progress remains slow.

19.4.6 Blacklisting of suppliers

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

19.4.7 Initiatives to enhance proactive management of fraud and corruption

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

19.4.8 Review of policies and procedures

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

19.4.9 Crime landscape risk assessment

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

The first phase of the crime landscape risk assessment is in progress, given the time needed to conduct interviews and obtain information for a project of this scale and complexity. The final report, including recommendations for treating root causes, is expected to be issued in the third quarter of the 2024 financial year.

Once the risk assessment is completed, recommendations around the design and implementation of control frameworks will be considered in the second phase, together with embedding a crime risk management programme as part of Eskom's standard operating procedures.

19.4.10 Single investigative unit

Eskom's Forensic and Anti-Corruption Department is mandated to perform independent forensic investigations into cases of fraud, corruption and general irregularities, supported by a panel of external investigators. In addition, Eskom has many other functions which are responsible for investigating and responding to crime and other unethical behaviour. The existing approach of having multiple investigative functions, operating in an uncoordinated manner at times, is not yielding the desired results. To enhance our effectiveness in preventing and responding to these matters, we have embarked on a programme to consolidate our multiple investigative functions into a single investigative unit. It is envisaged that a high-level structure for the investigative unit will be in place by December 2023, with full implementation planned by the end of the 2024 financial year.

19.5 Eskom's Fraud Prevention Plan

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

- Improving Eskom's ethical culture and legislative compliance
- Adopting and embedding a zero-tolerance approach to fraud and corruption in business operations

- Raising awareness of fraud through various fraud prevention campaigns and training interventions
- Improving the transparency and credibility of the procurement process
- Encouraging members of the public to blow the whistle on fraud, corruption and financial misconduct by publicising Eskom's whistle-blowing channels
- Enhancing fraud deep dives and fraud risk assessments
- Establishing an intelligence-driven forensic investigation capacity
- Supporting management in the implementation of consequence management, and improving oversight and management accountability

The Anti-Fraud and Corruption Integration Committee (AFCIC) was established in 2020 to monitor implementation of the fraud prevention plan each year and to ensure integration between forensic, legal, ethics, industrial relations and supplier review functions.

During the year, we conducted a self-assessment on our alignment to the goals and purpose of the OECD's recommendations on anti-corruption. The assessment identified gaps and enhancement opportunities related to certain business processes. A plan has been developed to address these gaps and implement enhancements in the 2024 financial year.

An anti-fraud and corruption strategy has been developed and will be updated to incorporate the results of the independent assessments on Eskom's crime landscape and ethics risks. Furthermore, a fraud risk assessment has been concluded, leading to the development of a fraud risk register for the organisation. AFCIC is monitoring progress of the implementation of the OECD's recommendations as well as controls linked to the fraud risk register, in line with its mandate.

Our Forensic and Anti-Corruption Department has also performed a fraud deep dive on the procurement of goods and services to identify exceptions, such as inflated prices and deliberate splitting of orders to circumvent controls. The external auditors have raised similar findings during the external audit for the 2022 financial year, and again for the 2023 financial year. Further analysis is being conducted on these findings and the recommendations to address these matters, although the Board is not satisfied with the level of progress made in improving internal controls across the organisation.

19.6 Whistle-blowing and conflict of interest management

All stakeholders, including employees, are encouraged to report suspected incidents of unlawful or irregular conduct involving Eskom's directors, employees or suppliers through our whistle-blowing channels. These channels are managed by an independent service provider to ensure the integrity and confidentiality of the process. All incidents are acknowledged within 24 hours and cases are registered for forensic investigation after conducting an initial assessment of the incident.

Compliance with and monitoring of the annual declaration of interest process has improved, with 99% of employees having submitted their declarations for the 2023 financial year. Where employees have not declared business-related interests or have performed private work without prior approval, they will be subjected to disciplinary processes.

Our declaration of interest system sources information directly from the Companies and Intellectual Property Commission (CIPC) database to ensure that any active directorships are appropriately disclosed. Exceptions that raise potential non-compliance with our conflict of interest policy are referred to our Forensic and Anti-Corruption Department for investigation.

19.7 Forensic investigations and disciplinary action

FORENSIC INVESTIGATIONS	
7 963 incidents registered for assessment on the forensic case management system through reporting channels	
278 new cases registered for forensic investigation	**227** forensic investigations concluded
305 cases under investigation at year end, relating to current and prior years	

SANCTIONS
223 employees recommended for disciplinary action
54 suppliers recommended for review to the Supplier Review Committee
158 confirmed cases of fraud and corruption registered with the South African Police Services (SAPS)

We have enhanced our forensic investigation process to make it compulsory for all internal and outsourced investigations to assess, during an investigation, whether a case is required to be reported to law enforcement agencies. This process has been implemented to ensure that all relevant matters are reported in terms of the Prevention and Combating of Corrupt Activities Act, 2004. Forensic investigating reports are only signed off once this requirement has been satisfied and, where applicable, a case number from SAPS or the Directorate for Priority Crime Investigation (the Hawks) has been assigned.

Of the 158 cases registered with law enforcement, 10 are at trial stage at various magistrate and specialist commercial crimes courts. A further 41 have been through the criminal proceedings provided for under the Criminal Procedure Act, 1977. Improved relationships with law enforcement agencies resulted in the arrests of more than 18 individuals during the year, including employees and suppliers who were implicated in fraudulent and corrupt activities.

Regrettably, our investigations have revealed similar themes to previous years, with instances of improper contract management, general procurement irregularities and fraud continuing. Non-compliance with Eskom's well-documented policies and procedures, employee dishonesty, such as through inaccurate or incomplete declarations on interest, as well as circumvention of controls remain the most prevalent themes in these cases. Eskom's Internal Audit Department has recommended control enhancements in affected areas to prevent recurrence and the correction of identified control deficiencies are being monitored.

19.8 Improving consequence management

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

The state capture task team has also reviewed key policies and procedures relating to the implementation of consequence management and has proposed an end-to-end process to manage integrity matters within Eskom, including fraud, corruption, breaches of the conflict-of-interest policy and the management of the whistle-blower hotline, among others. Separate disciplinary and grievance procedures are being implemented for bargaining unit and managerial employees, to align to Eskom's conditions of service and industry trends as well as institute separate standards for managerial employees due to the higher expected duty of care.

An agreement was reached with our recognised trade unions to institute the amended disciplinary and grievance procedures for bargaining unit employees from 1 July 2023. The amended procedures provide guidelines for disciplinary enquiries and hearings to ensure consistency in the application of consequence management. Eskom undertakes to institute disciplinary action within three months from the date that it becomes aware of any misconduct. Consultations on the disciplinary and grievance procedures applicable to managerial employees are in progress.

The Human Resources Division has revised its reference flagging procedures to include employees who resigned before disciplinary processes or investigations could be concluded. Previously, only employees who were dismissed were flagged. Individuals who have been flagged cannot be employed in Eskom for 10 years and cannot serve as an employee of a contractor on Eskom sites. The withholding of pension benefits and the recovery of losses or damages to Eskom from flagged employees are also outlined in the revised procedure.

In instances where suppliers have failed to declare a potential conflict of interest and have been proven to have benefitted unduly through such relations, a supplier review process is followed. Eskom's Supplier Review Committee investigates cases of misconduct and institutes disciplinary action, which may include blacklisting of suppliers from Eskom's database as well as recommendations to National Treasury for blacklisting of suppliers on the national supplier database. Our state capture task team is reviewing the backlog of supplier disciplinary cases and addressing new cases as they arise. An external service provider has been appointed to assist in closing these matters out.

19.9 Addressing security risks

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

Our focus remains on gathering intelligence on key criminal elements within and external to Eskom. We are collaborating with law enforcement and other criminal justice agencies to address possible shortcomings which prevent successful investigations and prosecutions on criminal matters.

Eskom's General Manager: Security has been placed on precautionary suspension to finalise an investigation into unverified messages and allegations of fraud and corruption linked to the awarding of an emergency security contract, which has been widely reported in the media. Given the seriousness of these allegations, Eskom is working with relevant authorities to investigate the matter. The emergency security contract was placed in line with Eskom's procurement procedures and National Treasury directives for the emergency procurement of services.

The National Prosecuting Authority (NPA) and its Investigating Directorate is working with legal experts and Eskom's forensic investigators to support its efforts in ensuring successful prosecution of alleged perpetrators of complex and high-profile cases. The NPA has also committed to increasing its collaboration with law enforcement authorities to focus on major crimes, such as cable theft and damage to essential infrastructure, which seriously threaten the operational sustainability of Eskom and other SOCs.

20 Conclusion

This RCA application is centered around the contry trying to balance the supply with the demand for electricity. The production plan demonstrates that only 50% of the anticipated energy supply by independent power producers materialised. The Eskom coal fired power, despite their availability, were overwhelmed and performed at extreme energy utilisation factors. This resulted in producing over 99% of anticipated energy. The nature of coal plant operations required further use of start-up fuel to continue to contribute towards meeting the demand. The only option left to continue to try to minimise load shedding was the utilisation of OCGT – both Eskom and IPPs. This resulted in a significant RCA balance applications. The variance for Eskom OCGT fuel is R17.6bn for the favour of Eskom. The outcome for the country was unfortunately over 13TWh of load shedding, which manifests in approximately R20bn adjustment for the benefit for the consumer. The resultant overall RCA balance application is R9m.

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