Generation Licensee (Gx)

Multi-Year Price Determination (MYPD) 6

Revenue Application for FY2026 – FY2028

Submission to NERSA

August 2024

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1.1 Context of Generation environment

Generation is operating an ageing Generation fleet with more than half of the power stations over 40 years of age. Due to various constraints, most notably inadequate capacity and financial limitations, the mid-life refurbishment and enhancement projects that are required to maintain and improve technical performance as plants age, have generally not been implemented. Together with high utilisation that places higher than expected wear and tear on components and systems, in particular since 2008, this has contributed to a steady decline in generating plant availability over the past decade.

Simultaneously, the projected new capacity from independent power producers (IPPs), have been delayed or cancelled. This led to an increase in utilisation of the open-cycle gas turbines (OCGTs) at high load factors as a mitigation against increased loadshedding. The high utilisation of OCGT has also had a negative impact on Eskom's financial performance to date.

Furthermore, in response to the country's capacity shortage and to minimise or avoid load shedding, Eskom has adopted a strategy to not shutting down any more units until at least 2030 at Camden, Hendrina, Grootvlei, Arnot and Kriel, all of which would have had units shutting down during this period until 2030. This requires increased maintenance interventions, which should be noted is significantly less than the costs of running OCGT's or loadshedding.

The constraints, particularly financial and capacity remain, and together with the phenomenon of the ageing fleet, has contributed to the current projected availability of approximately 56% EAF as at the end of FY2024. In order for this to improve it is imperative that tariffs move towards cost-reflectivity and that maintenance space is available to perform the required maintenance.

1.2 Revenue requirement summary

TABLE 1: GENERATION MYPD 6 REVENUE REQUIREMENT

Generation Allowable Revenue (R'm)	AR	Formula	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Regulated Asset Base (RAB)	RAB		828 717	909 656	893 438	870 825	861 267
WACC %	ROA	X	4.00%	5.00%	6.00%	7.47%	9.69%
Returns			33 149	45 483	53 606	65 085	83 491
Primary energy	PE	+	125 030	129 493	124 190	125 267	128 681
International purchases	PE	+	-	-	-	-	-
IPPs	PE	+	-	-	-	-	-
Environmental levy	L&T	+	6 539	6 279	5 337	4 781	4 767
Carbon tax	L&T	+	5 534	21 291	19 895	19 274	20 948

Generation Allowable Revenue (R'm)	AR	Formula	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Arrear debt	E	+	-	-	-	-	-
Employee Benefits	E	+	14 281	14 858	15 176	15 774	16 519
Maintenance	E	+	21 742	20 693	22 224	21 249	23 462
Other operating costs	E	+	19 070	19 487	20 027	20 912	21 016
Depreciation	D	+	53 054	55 406	61 921	62 927	67 812
Generation Allowable Revenue			**278 399**	**312 991**	**322 376**	**335 269**	**366 696**
Add: Approved RCA/court order for liquidation	RCA		13 241	10 961	-	-	-
TOTAL Generation Allowable Revenue	R'm		**291 640**	**323 952**	**322 376**	**335 269**	**366 696**

The table above, summarises the revenue requirement for the Generation licensee in accordance with the MYPD methodology with a proviso that the return on assets is not applied for as in the methodology, but is gradually phased over the MYPD 6 period. Please note that the IPP and international purchases related revenue is included in the National Transmission Company South Africa (Transmission) application.

1.3 Return on assets

The ERA and the Electricity Pricing Policy require the recovery of efficient costs and earning a fair return. In accordance with the MYPD methodology, Generation is allowed to earn a return on the Regulatory Asset Base (RAB).

TABLE 2: GENERATION MYPD 6 RAB

GENERATION - REGULATORY ASSET BASE (R'm)	Decision FY2024	Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Depreciated Replacement Costs (DRC)	677 641	633 995	611 670	572 153	533 036	494 789	457 585
Asset transferred to commercial operation post valuation date	45 961	28 757	224 221	256 027	281 300	287 587	325 403
Work Under Construction (WUC)	40 712	32 137	41 750	49 359	54 378	46 452	61 251
Net Working Capital	32 321	41 505	42 007	19 423	18 003	23 015	23 981
Assets Purchases	128	171	1 221	1 480	1 717	1 374	1 099
Assets funded upfront by customers	-	-	-	-	-	-	-
Total Regulatory asset base (RAB)	**796 763**	**736 565**	**920 870**	**898 442**	**888 434**	**853 216**	**869 319**
Average RAB		**766 664**	**828 717**	**909 656**	**893 438**	**870 825**	**861 267**

As summarised in the table above, the RAB value decreases over the MYPD 6 period as the fleet ages. In order to contain the impact of the overall Generation revenue requirement, a phasing-in of the return on assets was included, also as reflected in the table above. This contributes towards minimising the impact of the price increase on the consumer.

1.4 Primary energy

The total primary energy is inclusive of Eskom primary energy, carbon tax and the environmental levy. In order for the system operator to meet the demand, the dependence on IPPs has diminished. Thus, the additional dependence on Eskom's coal-fired power stations to fill this gap. It also results in securing more expensive coal to ensure continuity of supply.

The primary energy costs increases annually over the MYPD 6 period mainly as a result of the implementation of the Carbon Tax.

1.5 Operating expenditure

Generation's operating costs comprises of Maintenance, Employee benefit costs and all other operating expenditure. This expenditure over the MYPD 6 period is aligned to international norms.

1.6 Environmental compliance

The environmental clause in the Bill of Rights sets the context for environmental protection, providing for an environment which is not harmful to health and well-being and for ecological sustainable development. The National Environmental Act and several Strategic Environmental Management Acts (SEMA's) give effect to the environmental right in the Constitution. The development of environmental legislation has resulted in new and more stringent requirements which Generation is obligated to respond to in order to continue operating its power stations. Given the nature of Generation's activities these requirements are far reaching, they affect all the divisions and subsidiaries in some manner, including air quality, protection of the natural environment and biodiversity, water use and preventing pollution of water resources, general and hazardous waste management, the utilisation of ash and licensing processes. These legislative requirements are enforced through licences and permits. They lead to operational and capital expenses. To retain the licence to continue to operate, these expenses must be allowed for in the tariff, preferably in a manner which separates non-negotiable statutory requirements from refurbishment and maintenance expenses.

2 Structure of the Generation Licensee

The role of the Generation Licensee is to manage the full generation value chain from the construction of new generation plant, through to the production of electricity to the national grid. This includes the sourcing of primary energy, lifecycle management (which incorporates routine and regular maintenance activities as well as major refurbishment and performance improvement projects), production planning, outage planning, engineering services and the operation of the power stations to provide not only the energy to serve daily requirements and capacity to meet the peaks but also ancillary services to assist the grid operator in maintaining grid security.

The Generation Licensee includes the Generation Division which operates and maintains the power stations, but also houses Primary Energy which sources primary energy for the stations. The Renewables division also forms part of the Generation license. The Group Capital Division is responsible for the execution of capital projects. This includes the new build stations, as well as all major capital projects at the existing stations. In addition, there are a number of centralised service and strategic functions that provide services to the various Licensees. These include, but are not limited to, Finance, Human Resources, Commercial, Security, Stakeholder Management, and Sustainability which is responsible for both Environmental and Safety Management. The costs of these centralised services are allocated to the Generation Licensee based on various allocation criteria.

3 Financial Sustainability: The Eskom Context

Financial sustainability is the ability to cover operating costs from revenue and secure stable and sufficient returns to fund future growth, while maintaining and replacing the current asset base. Financial sustainability, in Eskom's context as an asset intensive state-owned entity, requires a return on assets which is at least equal to the cost of capital.

Capital funds can be sourced from either borrowings or equity, in the form of investment by the shareholder or retained earnings. The level of borrowings which Eskom is able to raise is dependent on the extent of current and future profitability and the strength of the balance sheet. Earning an appropriate return on capital will enable Eskom to accumulate sufficient equity to strengthen the balance sheet and migrate on a path towards financial sustainability.

It should be noted that the Eskom Debt Relief Act, 2023 was promulgated in July 2023 to provide relief of R254bn towards Eskom's debt servicing costs. The conditions attached to the Act provide strict restrictions that capital expenditure is limited to transmission and distribution, and Generation is only allowed to address MES, FGD, maintenance and completion of existing projects. Greenfield generation projects will only be allowed with approval of the Minister of Finance. New borrowings are prohibited during the debt relief period, and only existing drawdowns permitted, unless approved by the Minister of Finance.

To this end, the price of electricity has to be cost-reflective to ensure a fair return on capital and thereby financial sustainability. The lack of a cost-reflective price, as is currently the case, implies the non-recovery of efficient costs, and hampers the maintenance and replacement of existing assets to allow for growth in the business.

In a regulated environment, the predominant question that arises is how to determine whether the revenue allowed by the regulator, and consequently the unit selling price of the regulated product or service, is reasonable. In the context of the electricity supply industry, the starting point for determination of allowed revenue is the basic formula that is applied by energy regulators worldwide when regulating electricity prices in terms of a 'cost-of-service' methodology. This formula is illustrated below:

Revenue requirement = Primary energy costs + operating and maintenance costs + depreciation + return on assets

The average electricity tariff may then be calculated as:
Average tariff per kWh = Allowed revenue ÷ sales volumes (kWh)

The purpose of including each of the four components of the basic formula is as follows:

- Primary energy cost provides the revenue with which to pay for the fuel – such as coal, diesel and uranium – as well as other primary energy – such as water – that is required to generate electricity.

- Operating and maintenance cost provides the revenue with which to pay for the maintenance, employee costs, insurance costs and other operating expenditure which are incurred in order to operate power stations, transmission lines and substations, and distribution systems and services.

- Depreciation of assets provides the revenue, in instalments spread over the full operational life of the assets, with which to redeem the principal of the debt and equity capital that were initially raised for investment into the assets (on the basis that total debt and equity capital is always equal to total assets).

- Return on capital represents the cost of the debt and equity capital – such as interest expense – that is incurred on the unredeemed portion of capital. In terms of this formula, capital is redeemed at the same rate that the assets are depreciated; hence the unredeemed portion of total capital is always equal to the depreciated value of the assets, assuming a nominal return on capital. This also enables regulators, for reasons of practicality and convenience, to also calculate the amount of return on capital as a return on assets.

Revenue is set in advance based on assumptions, estimates and parameters for the applicable future periods. In a retrospective process the RCA mechanism reconciles the variances between (A) the revenue allowed by the regulator, including the assumptions, estimates and parameters upon which the revenue decision (e.g., MYPD decision) was based, and (B) the actual revenue and the actual outturn on certain of the assumptions, estimates and parameters. The mechanism allows for the adjustment of revenue and thus electricity prices in subsequent years, to compensate for the over or under-recovery of some of the preceding years' regulated costs and revenues, as approved by NERSA.

When considering the application, NERSA applies the principle of prudency and efficiency in terms of capital expenditure, operating costs and costs related to primary energy. It is Eskom's responsibility to ensure that it operates efficiently and that operating costs include only those that were prudently and efficiently incurred. The price of electricity will be cost-reflective if a return on capital (or assets) equal to the cost of capital is earned, with such return on capital calculated with the use of prudent and efficient costs.

The allowed revenue formula may be rewritten as follows:

Allowed revenue − (primary energy cost + operating and maintenance cost + depreciation) = return on assets (or capital)

Return on assets (capital) ÷ total capital (or total depreciated assets) = percentage return on assets (or capital)

In terms of the regulatory methodology, once actual costs have been adjusted by NERSA to what it considers prudent and efficient levels in RCA mode, such adjusted actual expenditure will not be fully recovered– and thus a revenue shortfall will occur – where the percentage return on capital, or percentage return on assets, (percentage return) is below the percentage weighted average cost of capital (WACC).

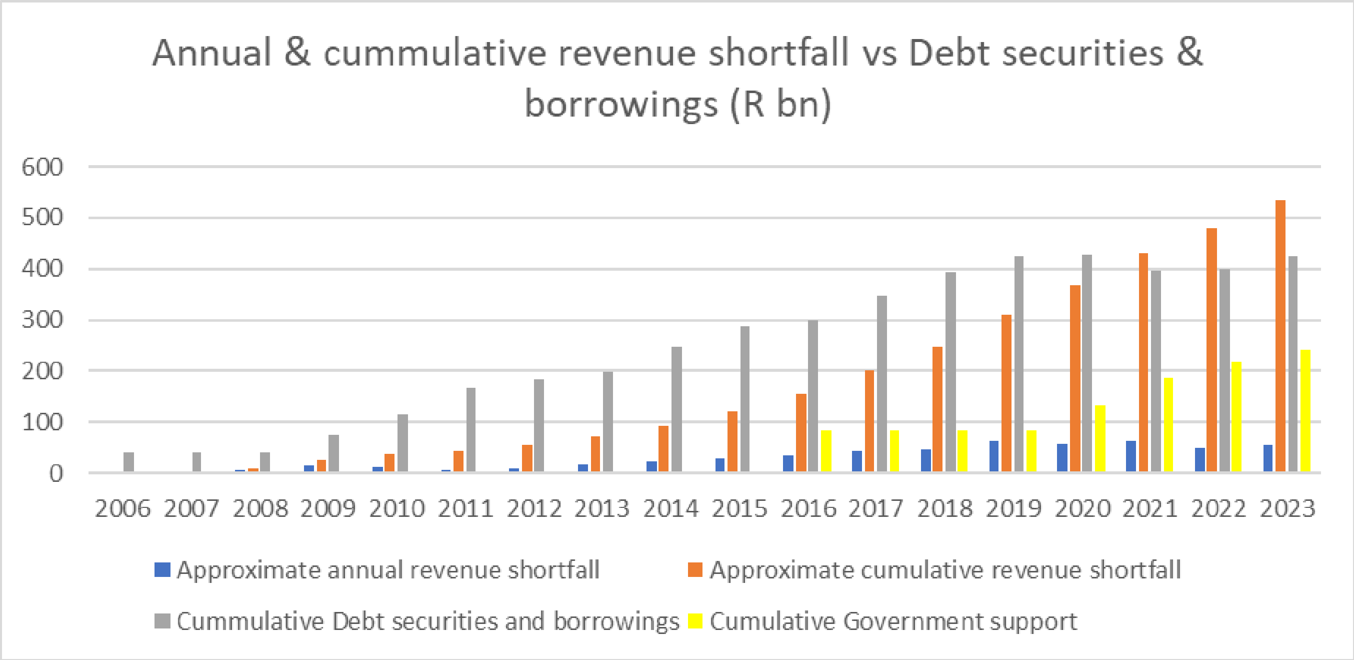
In order to better understand the root causes of Eskom's financial challenges and Eskom's significant debt burden, of R424bn debt securities and borrowings on the balance sheet by the end of FY2023, the principles discussed above are analysed within the Eskom context.

The impact of the lack of cost-reflective revenue and tariffs on Eskom's financial position

The lack of cost-reflective tariffs and resultant revenue shortfall has been an ongoing challenge since 2006 and is one of the main reasons for Eskom's financial constraints, requiring increased reliance on debt to fund the shortfall. This, together with the new build programme, has led to Eskom's debt securities and borrowings balance escalating to R424bn by the end of FY2023.

This sentiment of Eskom's sub cost-reflectivity has been corroborated by various independent parties over the years i.e., the credit rating agencies, World Bank, etc. It was acknowledged by the World Bank in their Policy Research Working Paper 7788 'Financial Viability of Electricity Sectors in Sub-Saharan Africa – Quasi-Fiscal Deficits and Hidden Costs' – August 2016, that "In the face of financial shortfalls, utilities are forced to cut O&M spending, starting a vicious downward spiral of asset degradation, declining operational efficiency, and deteriorating service quality", an accurate synopsis of current-day reality.

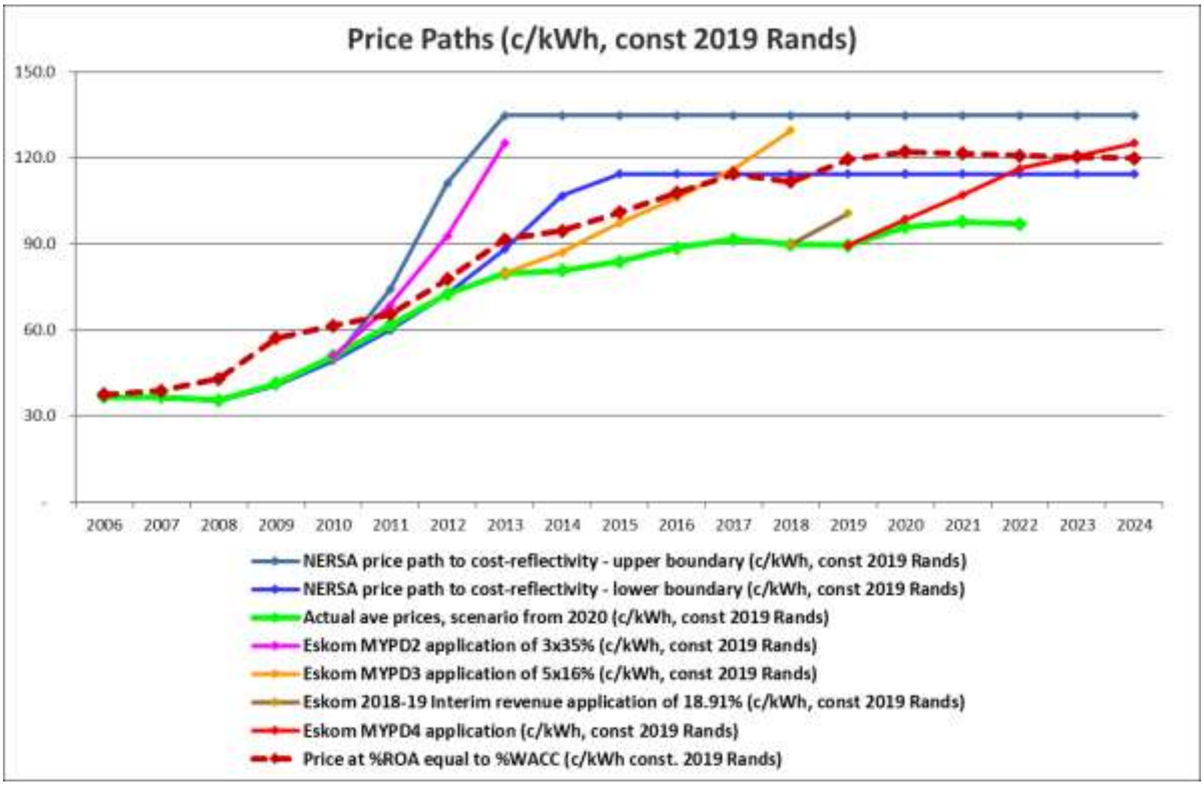
FIGURE 1: ANNUAL & CUMMULATIVE REVENUE SHORTFALL VS DEBT SECURITIES & BORROWINGS



From FY2013 to FY2016 the annual shortfall was between R18bn and R35bn per year. In FY2017 and FY2018 the annual shortfall rose to above R40bn per year, and in FY2019 above R60bn for the first time. The cumulative shortfall approached approximately R100bn by FY2014, R200bn by FY2017, R310bn by FY2019 and R424bn by FY2023. With no other option, these shortfalls had to be funded by raising additional debt and through government equity injections.

The graph below reflects what the annual average electricity tariff should have been in order to achieve returns equal to the pre-tax nominal WACC – this is illustrated by the dotted red line. In comparison, actual electricity tariffs charged – up to FY2019, thereafter the average tariffs implied by the MYPD 4 revenue determination – are indicated by the solid green line.

FIGURE 2: PRICE COMPARISON (C/KWH)



The difference between what tariffs should have been, and what they were, resulted in a cumulative shortfall in revenue of R310bn by FY2019 and over R400bn at present. The graph further reflects that the level that tariffs should have been compares well with the NERSA price path (upper and lower boundaries) as published in its reasons for decision document in June 2009. In addition, it aligns well to the tariff level of the least-cost scenario of the draft IRP 2019, as well as every other IRP since 2010.

The graph also indicates Eskom's revenue applications for MYPD 2, MYPD 3, the one-year application for FY2019, and MYPD 4, illustrating Eskom's efforts to restore the tariff to cost-reflective levels through our applications to NERSA.

For Eskom and the electricity supply industry to be financially sustainable, continue to operate and maintain its assets in a reliable state, as well as to meet the financial obligations related to existing and new infrastructure capacity, the average tariff will need to migrate to the level where the WACC can be recovered through cost-reflective tariffs – indicated by the dotted red line. Alternatively, as a temporary measure, given that debt borrowing capacity is almost fully saturated, Eskom will require Government support in order to address the annual after-tax revenue shortfall. Due to the continued delay in achieving revenues reflective of prudent and efficient costs, such government support has had to be provided since FY2020.

To reiterate, it was acknowledged by the World Bank in their Policy Research Working Paper 7788 'Financial Viability of Electricity Sectors in Sub-Saharan Africa – Quasi-Fiscal Deficits and Hidden Costs' – August 2016, that "In the face of financial shortfalls, utilities are forced to cut O&M spending, starting a vicious downward spiral of asset degradation, declining operational efficiency, and deteriorating service quality", an accurate synopsis of current-day reality.

4 Context of Generation Operating Environment

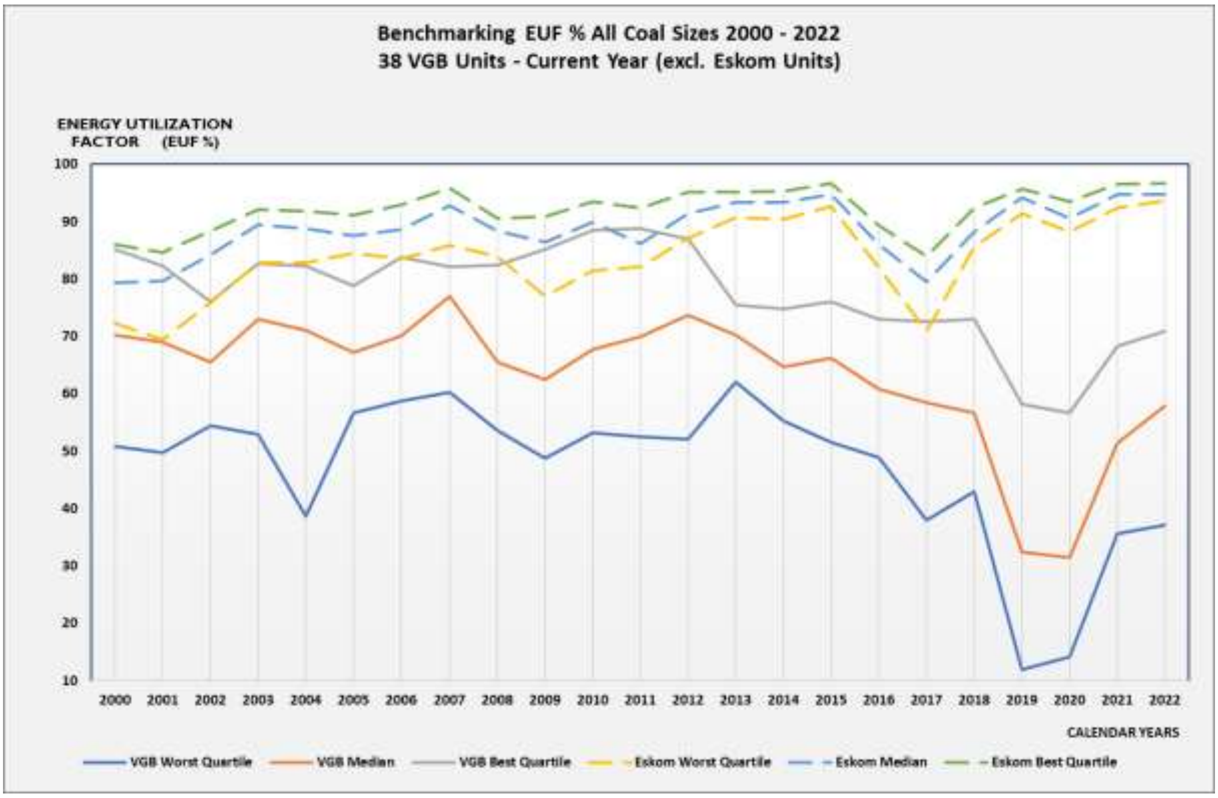
4.1 Environment

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

In terms of Eskom's internal 2035 Strategy and associated shutdown plan, Eskom had planned to shut down the remaining operating units at Camden, Hendrina and Grootvlei between January 2023 and September 2027. This internal strategy still required formal NERSA approval before it could be implemented. However, prior to applying to NERSA for formal approval, in response to the capacity shortage and to minimise or avoid load shedding, Eskom changed its internal strategy to one of not shutting down any more units until at least 2030 which includes Arnot and Kriel units which were also previously planned by Eskom to be shut down prior to 2030. In addition, Eskom is no longer planning that Tutuka should shut down early by 2030, which implies that additional funding is required in the MYPD 6 period to enable running beyond 2030. Despite this, compared to the previous and not yet approved by NERSA Eskom strategy for earlier shutdown, significant, additional, previously unplanned, funding will be required for the maintenance and operations of these units.

The performance of Generation's generating fleet is currently below aspiration. Although there are many contributing and aggravating factors, the root cause of this performance is the government's decision in the late 1990's that Eskom would not build any more power stations in South Africa. This decision was changed in the mid-2000's, which resulted in the late start of the build programme and progressively more severe capacity constraints from around 2002 onwards and manifesting as intermittent load shedding from 2008 onwards. This required that the existing plant had to be run exceptionally hard to meet the demand, accelerating the wear and tear on the ageing units. The graph below illustrates how Generation's coal-fired units were, for a period of about 15 years, run at an Energy Utilisation Factor (EUF) far higher than the international benchmark and higher than the normal and expected engineering and design parameters; thus in the "red zone". In particular, from 2012, Generation's lowest quartile was "run harder" than the top quartile of the benchmark stations in most years. When high EUF alone was not sufficient to meet the demand, from 2008 onwards the maintenance periods were being constrained as well in order to rather keep units running than being off-line for maintenance.

FIGURE 3: UTILISATION OF GENERATION'S COAL FLEET VERSUS INTERNATIONAL BENCHMARK



From 2008 onwards financial constraints due to primarily sub-cost-reflective regulated revenues started causing severe and increasing financial constraints. The combination of financial and capacity constraints meant that Generation was not able to implement most of the "mid-life refurbishments" that are required in order to maintain and improve the performance of the stations as they age.

It was initially assumed that the aspect of capacity constraints would be temporary and would be relieved once Medupi and Kusile were in full operation. However, although one expects performance challenges in newly commissioned stations, the performance of Medupi and Kusile as well as the pump-storage station, Ingula, were initially below aspiration. Once again, a major contributor, if not the root cause, is the capacity constraints due to the late start to the build programme. This resulted in a condensed design phase (FEED process i.e. Front End Engineering and Design) in order to accelerate the programme, which contributed to the execution problems on these projects and a ultimately a longer construction period, as well as to design faults that have resulted in a high level of plant failures after initial commissioning. These are being addressed with plant and procedure modifications and an improvement in performance has been seen.

As previously noted, although there are numerous contributing factors to the performance of Generation's generation fleet, the root cause goes back to the late 1990's. Eskom needed to make decisions on building new power stations by 1999 at the latest to meet demand by 2007 but, as acknowledged by former President Thabo Mbeki at the time, was not allowed to do so. This meant that the final investment decision could only be taken in December 2006 – too late to avert a capacity shortage. As explained above, this was later exacerbated by delays in the construction of Medupi and Kusile due to lack of sufficient time for undertaking a thorough design phase as a result of the late decision.

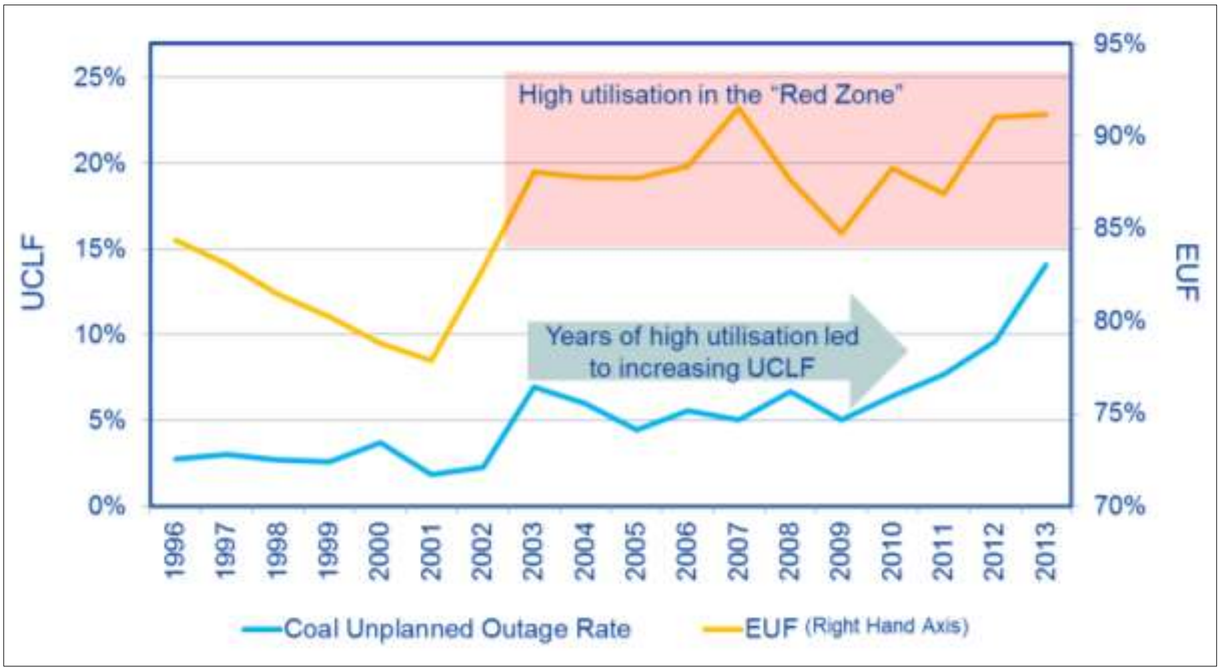
This all led to inadequate capacity to meet demand whilst leaving inadequate maintenance space to perform an ideal level of preventative maintenance, particularly mid-life refurbishments. As a power station reaches 25 to 30 years of operation, major systems and components need to be refurbished, replaced or upgraded to maintain and improve the performance of the stations.

Notwithstanding the high utilisation since 2003 and deferment of maintenance since 2008, Eskom's Generation fleet continued to perform well up to late-2012 with an availability of over 80%. The high plant utilisation and deferment of maintenance continued due to Eskom Generation operating in a constrained system capacity environment with a *de facto* obligation to meet national electricity demand, particularly in the lead up to and during the 2010 World Cup. This obviously had a negative impact on the health of the stations and thus their availability due to increased unplanned breakdowns. The decline in plant availability from 2012 meant that even less capacity was available to meet demand and thus required the available plant to run even harder resulting in a "vicious circle".

This situation was not sustainable and in subsequent years, planned maintenance levels and spend were increased despite the fact that this resulted in load shedding. This was essential but only possible because the Shareholder removed the Keep the Lights On (KLO) requirement from the Shareholder Compact from 1 April 2013. This increase in maintenance was the major contributor to the improvement in plant availability in FY2017 and FY2018. This improvement was, unfortunately, short-lived and availability started to decline again from late 2017. The reasons for this latest decline are many, complex and varied, with the main root causes still as explained above. The historical sub-optimal mid-life refurbishments and hard running of an ageing fleet (more than half – including Medupi and Kusile – over 40 years) still has the highest impact on plant failures, but increasing shortages of experienced skills and staff morale, driven by consistent sub-cost-reflective regulated revenues and uncertain future outlook are also amongst the contributing factors. The debt relief support from National Treasury to alleviate the immediate impact of sub-cost-reflective regulated revenues has recently allowed for the early ordering of long-lead spares for outages, which is starting to result in improved maintenance and improved plant performance.

The figure below illustrates how the generation fleet was operating at exceptionally high utilisation levels (EUF) of between 85% and 95% since 2003. Higher utilisation leads to additional stress on components and thus to increasing breakdowns but only after a delay. This is evident from the increasing unplanned unavailability (UCLF) from 2010.

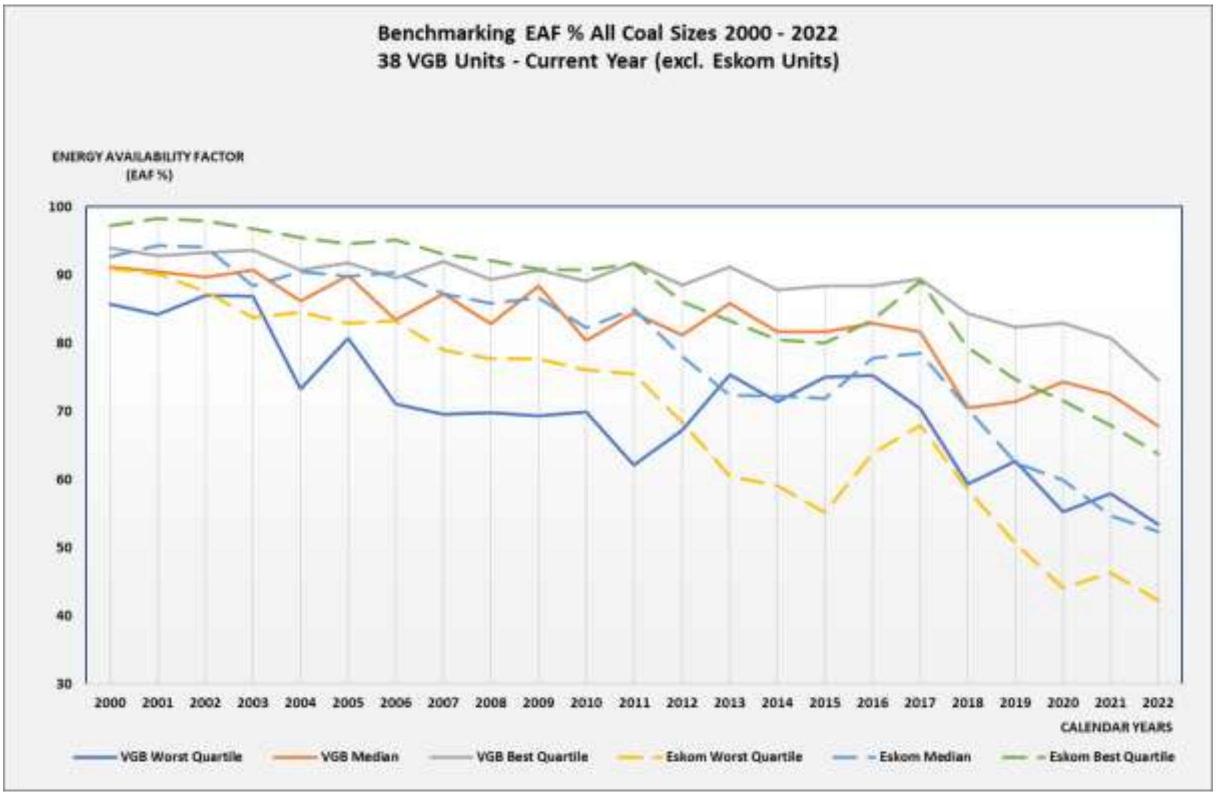
FIGURE 4: HISTORICAL COAL FLEET UCLF AND EUF - 1996 TO 2013



This trend of high utilisation has continued and even the lowest quartile stations have, in general, been running harder, at a higher utilisation, than the VGB benchmark.

Even without this exceptionally high utilisation, the ageing of the fleet, on its own, would lead to increased unavailability, particularly when not all the ideal mid-life refurbishments could be carried out due to financial and capacity constraints. This trend of a decreasing availability as a fleet ages can also be seen in the performance of the VGB benchmark fleet.

FIGURE 5: GENERATION'S COAL FLEET AVAILABILITY VS THAT OF THE VGB BENCHMARK

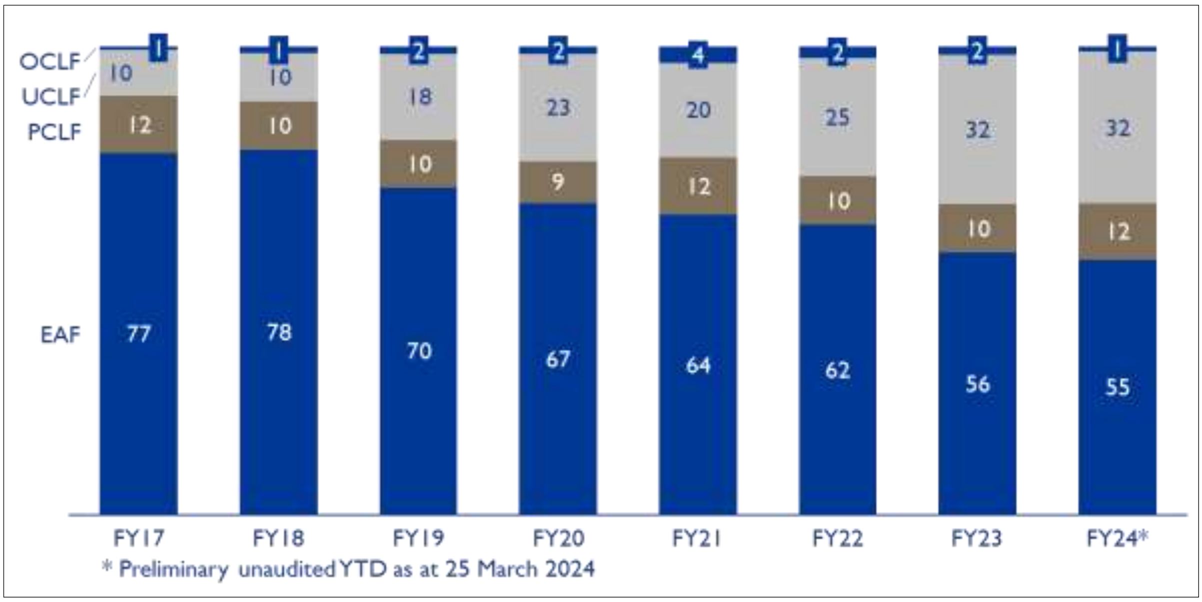


4.2 Generation technical performance parameters

One of the main technical performance metrics is the energy availability factor (EAF). EAF is calculated as 100% less PCLF, UCLF and OCLF. PCLF refers to planned capability loss factor, UCLF refers to unplanned capability loss factor and OCLF refers to other capability loss factor where the cause of the energy loss is outside of plant management control.

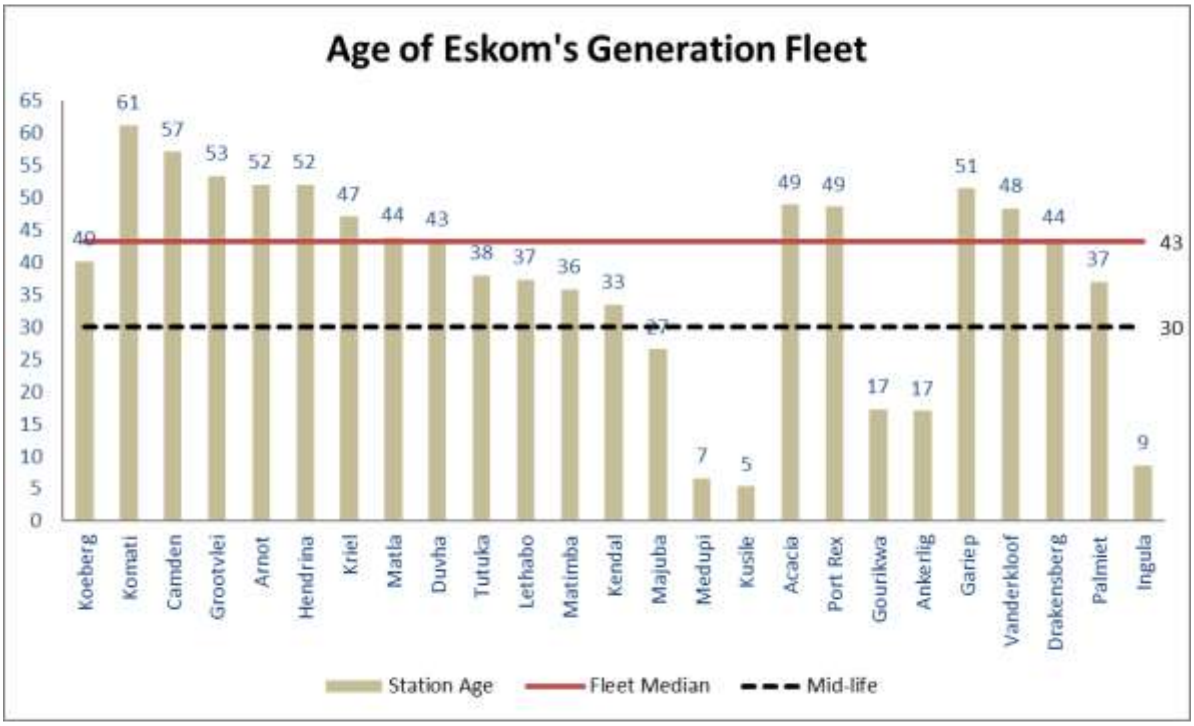
The Eskom Generation fleet's availability – EAF has declined significantly from a high of 78.0% in FY2018 to 64.2% in FY2021 and to 56% towards the end of FY2024. Prerequisites for improving the EAF include a migration to cost reflective tariffs to enable adequate funding as well as additional national capacity to enable adequate maintenance space to execute the required performance improvement and stabilisation maintenance, including the ability to enable early release of funds for timeous ordering of long-lead items.

FIGURE 6: PERFORMANCE OF GENERATION'S FLEET



Eskom Generation operates an ageing Generation fleet, notwithstanding the new stations recently completed with only 1 remaining Kusile unit under construction. More than half of the generation stations will be 43 years and older by the beginning of the MYPD 6 period.

FIGURE 7: AGE OF GENERATION'S FLEET AT 1 APRIL 2025



Due to various constraints, most notably inadequate capacity and financial limitations, the mid-life refurbishment and enhancement projects that are required to maintain and improve performance as plants age have generally not been implemented. Together with increasingly higher utilisation since 2002, which places higher than expected wear and tear on components and systems, as well as deferment of maintenance in particular since 2008, this has contributed to a steady decline in generating plant availability over the past 2 decades.

Due to a combination of additional maintenance, performance improvements, additional capacity from Generation and IPPs, as well as stagnant demand, the rapid decline in availability post 2012 was arrested and availability improved to 78% by FY2018. The constraints, which are also the main enablers namely finance and national system capacity, however, remained and these, together with the phenomenon of the ageing fleet, have contributed to the current availability of approximately 56% EAF. Generation's medium-term aspiration is to improve EAF for its fleet but reversing the overall trend remains a challenge.

TABLE 3: ASSUMED GENERATION EAF

EAF (%)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Energy Availability Factor (EAF)%	56.5	55.96	61.0	63.0	64.0	65.0	66.0	67.0
Stress Test %		55.5	55.9	57.0	58.0	59.0	60.0	61.0

The Generation units remain unpredictable and unreliable, and this uncertainty results in a requirement to use more conservative assumptions in the application. This can be seen in the Figure, above. In addition, as a risk mitigation, Eskom has included a Stress Test where the major difference is a lower EAF than the application.

4.3 Stress Test

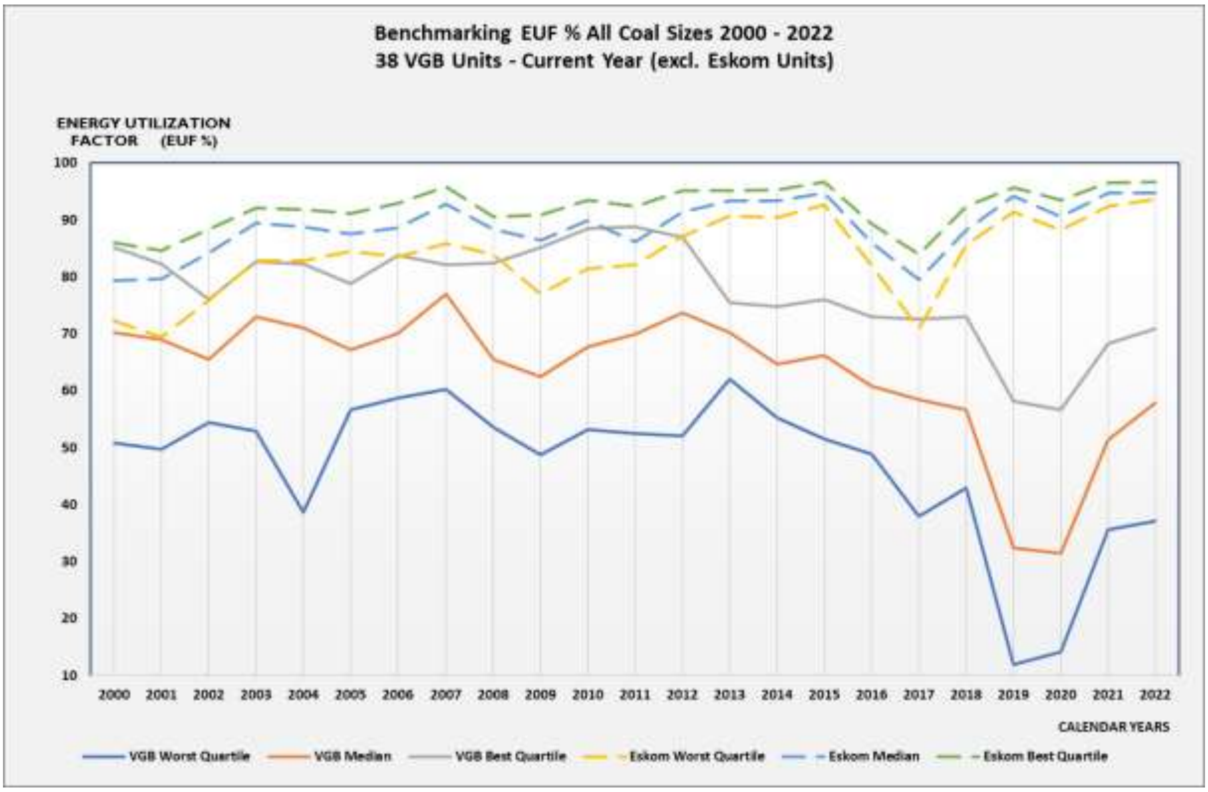
The uncertainties have required Eskom to include a Stress Test production plan in the application. Refer to Stress Test section under Production Planning chapter below.

4.4 Plant performance benchmarks

Eskom benchmarks its generating plants' technical performance against similar stations using VGB Powertech (VGB), of which Generation is a member. The latest available data from VGB is for the 2021 calendar year. Note that Generation data is also in calendar years.

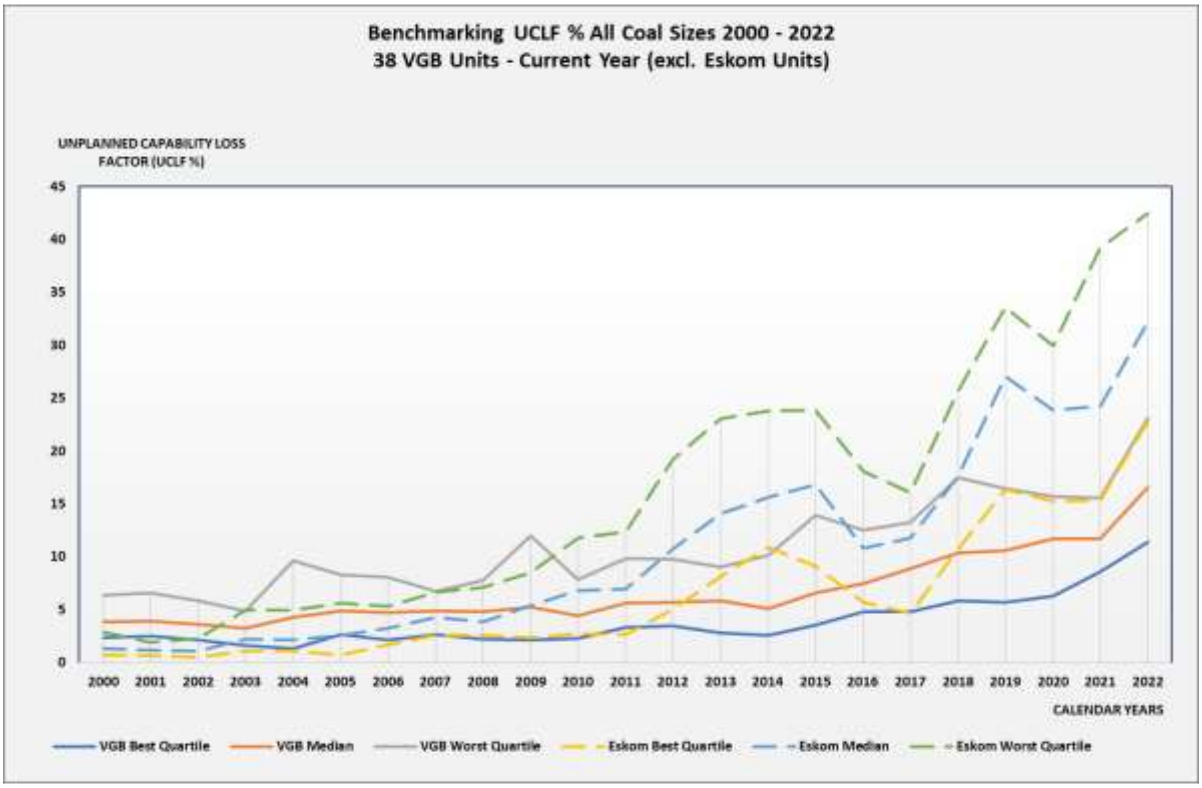
For more than the last two decades, Generation's fleet has been running at higher EUF than the VGB benchmark (not a good situation, with longer term risks as explained above). This is indicative of the constrained environment in which Generation has been operating and is a contributor to the current reduced availability due to additional stress on an ageing fleet. Until around 2012, the availability of Generation's plant was still higher than the benchmark, however from 2012 onwards the combination of high utilisation and deferred maintenance started manifesting in higher UCLF and thus reduced EAF.

FIGURE 8: ENERGY UTILIZATION FACTOR (EUF) BENCHMARKING



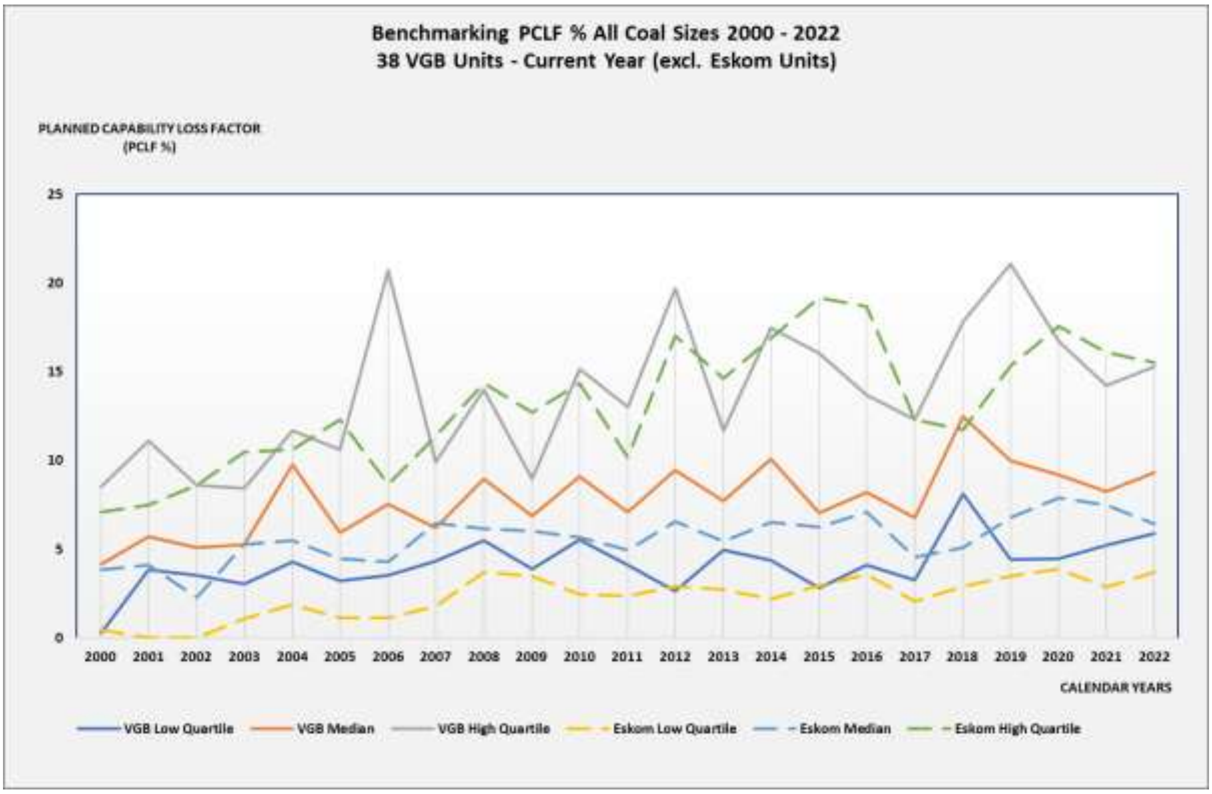
EUF measures "how hard" the units are being run and thus is an indicator of the wear on systems and components. From the figure above, it can be seen that Generation coal units have been consistently run harder than the coal units of the other VGB members. In particular, since 2012, even Generation's lowest quartile stations have mostly been running at a higher utilisation than the VGB highest quartile.

FIGURE 9: UNPLANNED CAPABILITY LOSS FACTOR (UCLF) BENCHMARKING



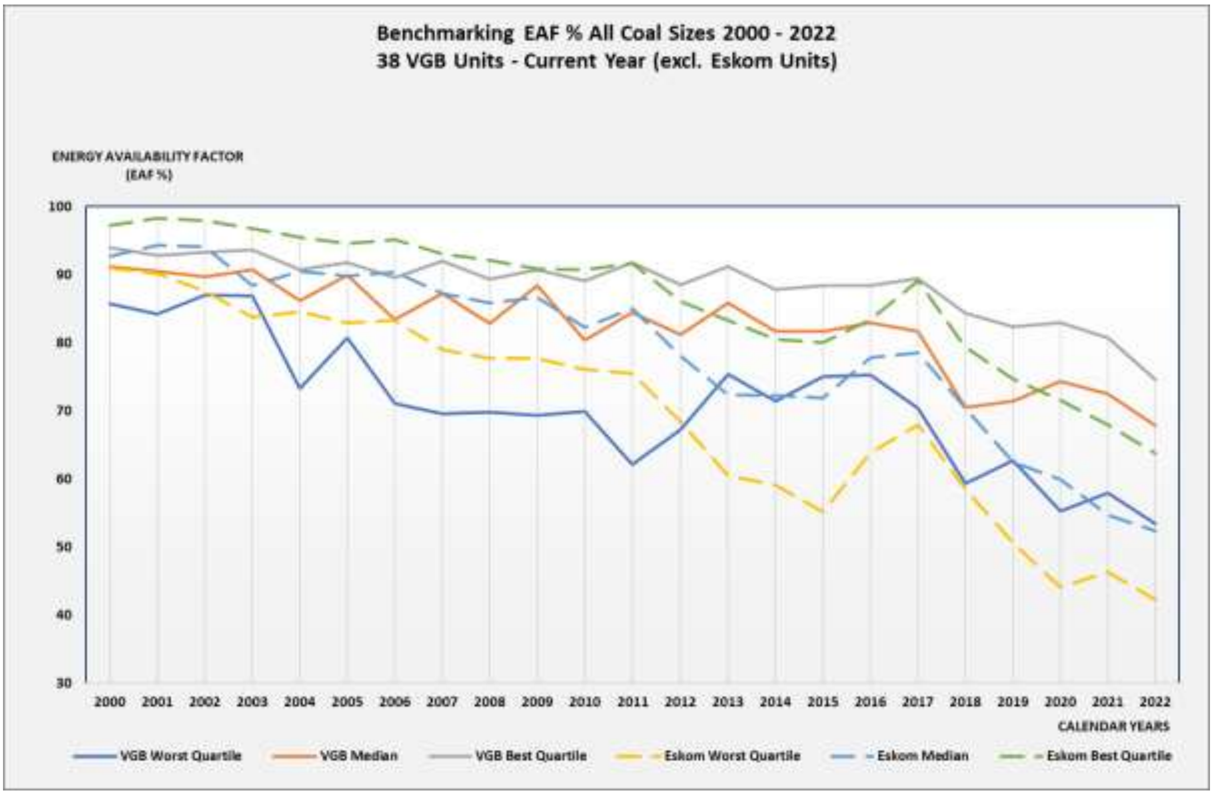
Until 2010, Generation's UCLF performance was in line with the VGB benchmark but deteriorated significantly from 2011 to 2015. Despite the improvement in 2016 and 2017, Generation's UCLF has deteriorated and is now significantly worse than that of the benchmark.

FIGURE 10: PLANNED CAPABILITY LOSS FACTOR (PCLF) BENCHMARKING



Until 2011, planned maintenance was consistently under the benchmark (The graph probably understates the situation given that the peer group's PCLF is not set in a context of extremely high plant utilisation). Since around 2015 PCLF was increased significantly, particularly on those stations most in need, as can be seen by the top Quartile being higher than the VGB top Quartile until 2017. Generation's median planned maintenance continues to be lower than the benchmark due to the constrained capacity and finances where planned maintenance could not be ideally undertaken.

FIGURE 11: ENERGY AVAILABILITY FACTOR (EAF) BENCHMARKING



Since 2012, the availability of Generation's coal fleet has dropped below that of the benchmark, notwithstanding the improvement in 2017 and 2018. The general trend, for both Generation and the VGB benchmark units is that of reducing availability. This is consistent with the expectation due to a generally ageing fleet. Generation's EAF has further deteriorated in recent years.

4.5 External Reviews

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

A comparative analysis of these reports has identified that some of the recommendations highlight recurring themes amongst these reports which indicated that there is a gap with regards to the effectiveness in addressing the recommendations. These themes can be divided into three categories, namely, People, Leadership and Human performance; Plant Performance and Processes; Governance and Finance.

The reports have thus been revisited to identify the implementation shortcomings and are being actioned and integrated into the Generation Recovery office tracking application to ensure oversight.

Multiple actions and programmes are already in place to address the shortcomings highlighted in the reports. Generation is managing the recommendations and actions and will continue to drive their implementation. Central organisational actions are being incorporated into the Generation recovery plans under the Recovery office. A main enabler is the debt relief support received from National Treasury.

Since the Eskom Board approval of the Generation Recovery plan in March 2023, Generation is confident that significant progress is being made in addressing systemic organization challenges.

5 Production Planning

5.1 Production Planning Objective

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

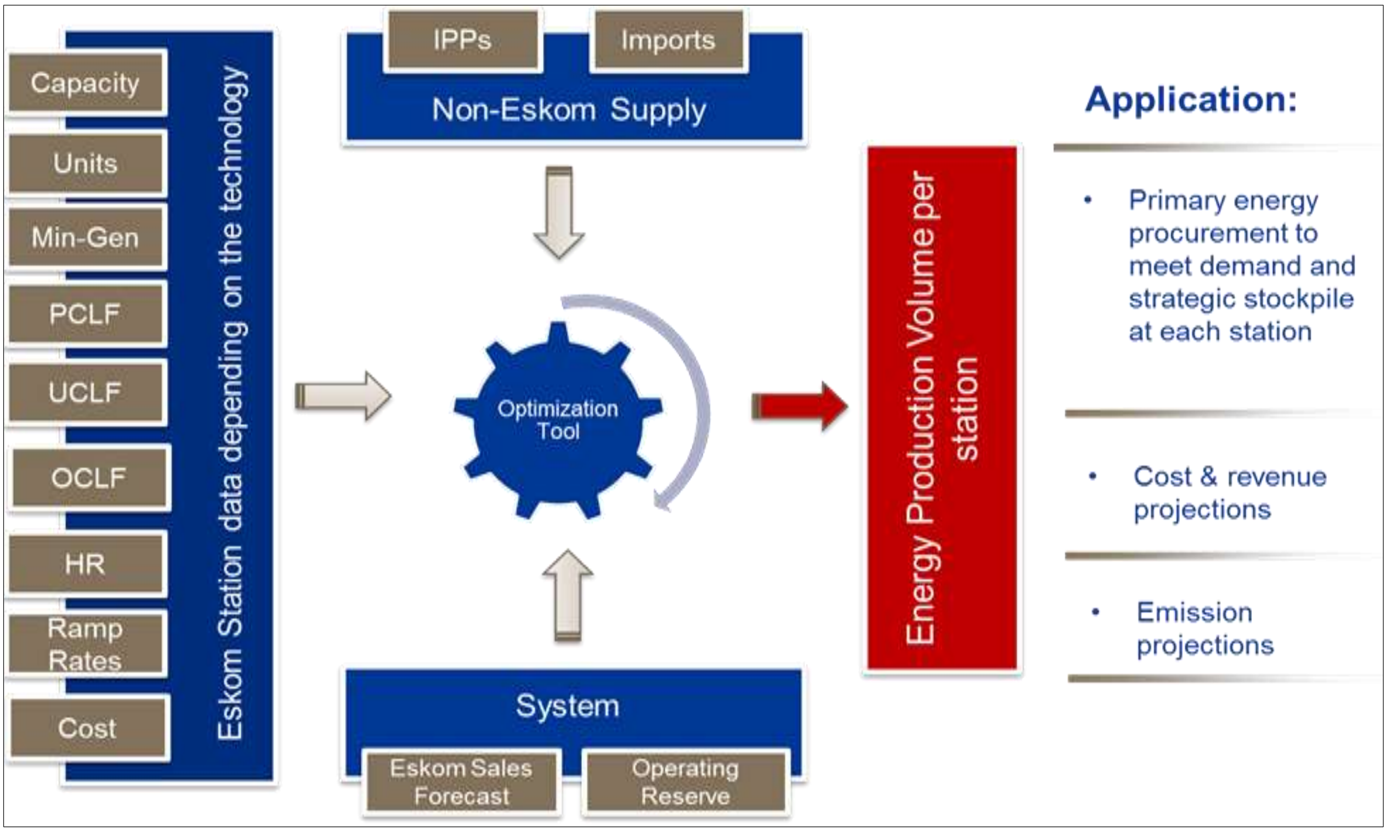
Merit order dispatch is derived from the primary energy costs (mainly coal and diesel cost) as well as power station burn rates (station efficiency and coal quality) resulting in an energy cost (R/MWh) ranking per station from the cheapest to the most expensive. Coal and diesel costs are the major contributors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

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

5.2 Production Planning Process

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

FIGURE 12: OVERALL PRODUCTION PLANNING PROCESS



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

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

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

The OCGTs are constrained by possible fuel deliveries per month. For Eskom OCGTs, the total fuel delivery constraint for all sites is equivalent to 650 GWh per month which is based on the historical maximum energy ever produced in a month. The IPPs are constrained to maximum 25% load factor per month due to fuel delivery limitations. Eskom and IPP OCGTs are optimized based on their variable cost as an emergency supply and assumed to produce at least at a 6% load factor per annum to cater for a quick response against any unforeseen events occurring on the system which could result in loadshedding. It should be noted that the OCGT load factors could increase significantly beyond 6% as envisaged by the stress tested production plan.

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

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

5.3 Production Planning Assumptions

The plan was developed based on the Eskom Generation continued operations strategy which intends to operate all the currently operating units at Grootvlei, Hendrina, Camden, Arnot and Kriel until to at least FY2030. Therefore, all stations/units are kept operational until FY2030 which includes Acacia and Port Rex.

It must be noted that the useful life of the power station is not determined by age but also by factors such as economic viability and strategic considerations. The main assumptions include:

5.3.1 Generation Capacity

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

TABLE 4: GENERATION EXISTING CAPACITY

Power station capacities as at 01 January 2024

The difference between installed and nominal capacity reflects auxiliary power consumption and reduced capacity caused by the age of plant.

Name of station	Location	Years commissioned - first to last unit	Number and installed capacity of generator sets MW	Total installed capacity MW	Total nominal capacity MW
Base-load stations					
Coal-fired (15)				44 598	39 099
Arnot [2]	Middelburg	Sep 1971 to Aug 1975	6x370	2 220	2 100
Camden [1, 2]	Ermelo	Mar 2005 to Jun 2008	3x200; 1x196; 2x195; 1x190; 1x185	1 561	1 481
Duvha [8]	Emalahleni	Aug 1980 to Feb 1984	5x600	3 000	2 875
Grootvlei [1,7]	Balfour	Apr 2008 to Mar 2011	4x200; 2x190	1 180	570
Hendrina [2,6,7]	Middelburg	May 1970 to Dec 1976	5x200; 1x195; 1x191; 1x170; 1x 167	1 723	1 098
Kendal [3]	Emalahleni	Oct 1988 to Dec 1992	6x686	4 116	3 840
Komati [1,7,11]	Middelburg	Mar 2009 to Oct 2013	4x100; 4x125; 1x90	990	
Kriel	Bethal	May 1976 to Mar 1979	3x430; 3x500	2 790	2 640
Lethabo	Vereeniging	Dec 1985 to Dec 1990	6x618	3 708	3 558
Majuba [2,3]	Volksrust	Apr 1996 to Apr 2001	3x657; 3x713	4 110	3 807
Matimba [3]	Lephalale	Dec 1987 to Oct 1991	6x665	3 990	3 690
Matla	Bethal	Sep 1979 to Jul 1983	6x600	3 600	3 450
Tutuka	Standerton	Jun 1985 to Jun 1990	6x609	3 654	3 510
Kusile [3]	Ogies	Aug 2017 to	4x799	3 196	2 880
Medupi [3,10]	Lephalale	Aug 2015 to Aug 2022	5x794; 1x790	4 760	3 600
Nuclear (1)					
Koeberg	Cape Town	Jul 1984 to Nov 1985	1x964; 1x970	1 934	1 854
Peaking stations					
Gas/liquid fuel turbine stations (4)				2 426	2 409
Acacia	Cape Town	May 1976 to Jul 1976	3x57	171	171
Ankerlig	Atlantis	Mar 2007 to Mar 2009	4x149.2; 5x148.3	1 338	1 327
Gourikwa	Mossel Bay	Jul 2007 to Nov 2008	5x149.2	746	740
Port Rex	East London	Sep 1976 to Oct 1976	3x57	171	171
Pumped storage schemes (3) [4]				2 732	2 724
Drakensberg	Bergville	Jun 1981 to Apr 1982	4x250	1 000	1 000
Palmiet	Grabouw	Apr 1988 to May 1988	2x200	400	400
Ingula	Ladysmith	June 2016 to Feb 2017	4x333	1 332	1 324
Hydroelectric stations (2) [5]				600	600
Gariep	Norvalspont	Sep 1971 to Mar 1976	4x90	360	360
Vanderkloof	Petrusville	Jan 1977 to Feb 1977	2x120	240	240
Wind energy (1)					
Sere [9]	Vredenburg	Mar 2015	46x2.3	100	100
Other hydroelectric stations (4)				61	2
Mbashe [9]	Mbashe River		3x14	42	-
First Falls [9]	Umtata River		2x3	6	-
Ncora [9]	Ncora River		2x0.4; 1x1.6	2.4	2.4
Second Falls [9]	Umtata River		2x5.5	11	-
Total Generation power station capacities (30)				52 452	46 788
Nominal capacity					89.20%
Total Generation power station capacities (30) less wind and other hydros				52 290	46 686
Nominal capacity					89.28%

1. Former moth-balled power stations that have been returned to service. The original commissioning dates were:
   Komati was originally commissioned between Nov 1961 and Mar 1966.
   Camden was originally commissioned between Aug 1967 and Sep 1969.
   Grootvlei was originally commissioned between Jun 1969 and Nov 1977.
2. Due to technical constraints, some coal-fired units at these stations have been de-rated.
3. Dry-cooled unit specifications based on design back-pressure and ambient air temperature.
4. Pumped storage facilities are net users of electricity. Water is pumped during off-peak periods so that electricity can be generated during peak periods.
6. Hendrina unit 3 is under extended inoperability
7. Due to financial constraints, some units at these stations have been placed in reserve storage and their capacity removed from the nominal base.
8. Duvha Unit 3 Recovery Project has been cancelled
9. Transferred to the Generation Division from 1 March 2021 but are not currently considered for Technical KPI calculations.
10. Medupi Unit 4 in Extended Inoperability from 01 October 2022 till August 2024
11. All units have been shutdown and the station is to be Repowered and Repurposed

Eskom is in the process of applying for licence amendments for the capcities that have been taken out of operation. These include 3 units at Grootvlei and 3 units at Hendrina. NERSA have approved the removal of Duvha 3 and Hendrina 3 from the nominal total capacity and its placement in reserve.

Additionally, Generation has submitted an application to NERSA for the amendment of the Generation licence to remove Komati coal units from operation with the intention to add renewable energy capacity at this site (Komati will be used for synchronous condensor operation).

Peaking and Koeberg units are assumed to be decommissioning at 60 year life of plant plan.

5.3.2 Generation new build capacity assumptions

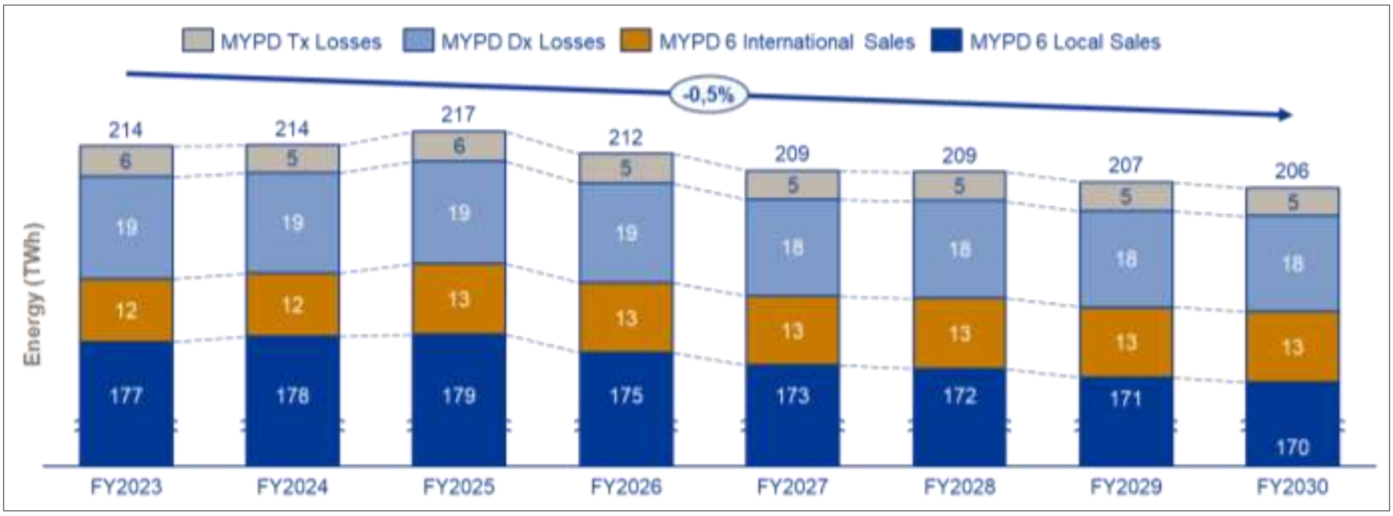
Eskom new build dates assumed in the production plan inputs are based on latest forecast of commercial operational dates. The only remaining unit to be commercialised in this window is Kusile Unit 6 in February 2025.

5.3.3 Energy forecast assumptions

As included in the Distribution Licensee submission, the energy forecast is robustly undertaken within Generation. For production planning purposes, the source of the energy forecast is the Energy Wheel Diagram. The forecast provides an indication of the energy sales from International exports, Distribution and Transmission national sales per month and/or annum. Distribution and Transmission line losses are added to these sales to arrive at the total energy forecast for a month or year.

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

FIGURE 13: ENERGY FORECAST AS PER WHEEL DIAGRAMME



5.3.4 Non-Generation supply assumptions

Non-Generation supply includes Independent Power Producers and International imports. The International imports consist of mainly Cahora Bassa. The IPP initiatives are included up to Bid Window 8 which includes gas programme, risk mitigation programme, emergency generation, standard offer and battery storage. Generation generators supply the balance after imports and IPPs have been utilised.

TABLE 5: INTERNATIONAL IMPORTS AND INDEPENDENT POWER PRODUCERS (GWH)

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

5.3.5 Generation Plant Performance

Plant Performance Indicator assumptions data determine the availability of the generating plant, its technical performance and the constraints within which the available plant will be operated. These data include unplanned capability loss factor (UCLF) estimates, other capability loss factor (OCLF) estimates, planned capability loss factor (PCLF) and any other specified technical constraints. The Generation Plant Performance Energy Availability Factor (EAF) is projected to improve during the MYPD6 period as indicated in the table below. It is important to note that this target is subject to production plan assumptions materialising and associated funding obtained.

TABLE 6: GENERATION TECHNICAL PERFORMANCE

Gx Technical performance (%)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Energy Availability Factor (EAF)	56.5	56	61.0	63.0	64.0	65.0	66.0	67.0
Planned Capacity Loss Factor (PCLF)	10.4	11.5	10.5	10.5	10.5	10.5	10.5	10.5
Unplanned Capacity Loss Factor (UCLF)	31.5	31.1	27.0	25.0	24.0	23.0	22.0	21.0
Other Capacity Loss Factor (OCLF)	1.6	1.4	1.5	1.5	1.5	1.5	1.5	1.5

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

5.1 OCGT usage

Eskom and IPP OCGTs are optimized based on their variable cost as an emergency supply and assumed to produce at least at a 6% load factor per annum to cater for a quick response against any unforeseen events occurring on the system which could result in loadshedding. It should be noted that the OCGT load factors could increase significantly beyond 6% as envisaged by the stress tested production plan.

5.2 Approval and monitoring of Production Plan

The draft Production Plan from the optimisation process is submitted for approval through the governance process, following which it is implemented. The Energy Wheel Diagram is then updated to reflect the final Production Plan.

The actual performance versus the assumption in the plan is monitored during the year of operation. Actual versus assumed production variances are investigated and reasons for the variances are reported to the relevant stakeholders. The power stations' actual production performance is monitored and reported on a monthly basis. The year-end plan is revised on a quarterly basis for the months ahead. In managing the system, Generation, Transmission and other relevant role-players meet once a week to look at the week ahead risks to production and devise mitigations accordingly.

The Production Plan for the remaining months of the year is revised quarterly due to a revised planning parameters. During the quarterly revisions, changes in sales forecast, forecast volume of energy imports, IPPs production, plant technical indicators, coal issues related to fuel delivery and stockpile days, and nuclear Production Plans are considered. The Production Plan may be revised outside quarterly intervals due to major events on the system.

5.3 Production Plan Outcome

The EUF decreases from 80% in FY2024 to about 40% in FY2030. As a result, some higher production-cost power stations (based on merit order informed by primary energy cost) are expected to be utilised less to meet the demand. The system dynamics can change at any time due to inherent risks such as unavailability or delay of IPP projects, sudden increase in demand, and lower than expected plant performance among other risks. These higher production-cost power stations will serve as the risk mitigation since they can be utilised more in the instances of capacity shortages. Also based on the current assumptions, both IPP and Generation OCGTs are kept at 6% load factor per annum for the entire planning cycle for a quick in response in the system.

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

TABLE 7: ENERGY PRODUCTION PER PLANT MIX (GWH)

Electricity output (GWh)	Actuals FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Power sent out by Eskom stations, GWh (net)	191 307	183 900	186 036	177 260	170 156	145 802	131 296	130 594
Coal-fired stations (incl. Pre-Commissioning), GWh (net)	171 131	*167177*	*170 108*	*159 704*	*149 556*	*126 241*	*110 616*	*109 723*
Hydroelectric stations, GWh (net)	3 060	*945*	*832*	*779*	*616*	*830*	*830*	*696*
Pumped storage stations, GWh (net)	4 081	*4793*	*4 522*	*4 242*	*4 055*	*4 188*	*4 224*	*4 002*
Gas turbine stations, GWh (net)	3 018	*2 539*	*1 266*	*1 266*	*1 266*	*1 266*	*1 266*	*1 266*
Wind energy, GWh (net)	214	*314*	*307*	*304*	*304*	*304*	*304*	*308*
Nuclear power station, GWh (net)	9 803	*8 131*	*9 001*	*10 965*	*14 359*	*12 973*	*14 056*	*14 599*
IPP purchases, GWh	17 957	22 972	23 856	31 364	35 214	57 259	71 610	70 952
Wheeling, GWh	2 904	2 152	2 826	2 723	2 723	2 831	2 826	2 826
Energy imports from SADC countries, GWh	8 654	9 295	9 776	6 601	6 449	8 573	6 930	6 930
Total Gross Energy sent output, GWh	220 822	**218 320**	**222 493**	**217 948**	**214 543**	**214 464**	**212 662**	**211 301**
Less Pumping	5 504	6 469	5 901	5 539	5 294	5 464	5 517	5 225
Total Net Production, GWh	**215 318**	**211 815**	**216 592**	**212 409**	**209 249**	**209 000**	**207 145**	**206 077**

5.4 Conclusion on the production plan

As can be observed by the results in the table above, the Generation energy sent out drops from 216 592 GWh (FY2025) to 114 283 GWh in FY2030, whilst Generation market share decreases from 84% to 62% in the same period. The IPPs' market share will increase from 11% in FY2025 to 34% in FY2030. As the plant availability stabilises and new capacity is added into the grid, energy growth remains stagnant and plant utilisation will drop. The Energy Utilisation Factor (EUF) for coal fired power stations drops from 82% in FY2025 to 46% in FY2030, whereas EUF for Generation system drops from 72% in FY2025 to 45% in FY2030.

5.5 "Stress test" on production planning

The Production Plan used for the MYPD 6 application is based on a plant availability of between 63% in FY2026 to 65% in FY2028, which is Generation's aspiration. However, current availability, as per the year-end projection for FY2024 is an EAF of 56%. Availability of the Generation fleet is one of many assumptions in the Production Plan. Others include the energy forecast and changes in the Generation and IPP new build programmes.

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

TABLE 8: STRESS TEST ENERGY FORECAST AND PLANT PERFORMANCE ASSUMPTIONS

Stress Test Assumptions	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
MYPD6 energy Forecast (TWh)	217	212	209	209	207	206
Stress Test energy Forecast (TWh)	224	222	221	222	220	219
Variance (TWh)	7	10	12	13	13	13
Stress Test EAF (%)	56.0%	57.0%	58.0%	59.0%	60.0%	61.0%

The Risk Mitigation Programme, Emergency Generation, Standard Offer, the IPP Gas Programme and some REIPP projects are assumed to be delayed by between 12 to 24 months based on the risk factors considered. However, load shedding reduction programme was completely removed from the stress test production plan. The combination of these assumptions provides for the worst-case scenario, where higher sales, lower plant performance and the delay in the IPPs is assumed.

TABLE 9: NON-GENERATION CAPACITY ASSUMPTIONS FOR WIND

Wind	Capacity (MW)	MYPD 6 Date	Stress Test Date	Delay
Wind Bid Window 5	140	Aug-24	Aug-25	12 Months
Wind Bid Window 5	140	Nov-24	Nov-25	12 Months
Wind Bid Window 5	280	Dec-24	Dec-25	12 Months
Wind Bid Window 5	224	Jan-25	Jan-26	12 Months
Wind Bid Window 7	3200	Mar-27	Sep-28	18 Months
Wind Bid Window 8	3200	Dec-27	Jun-29	18 Months

TABLE 10: PV STRESS TEST ASSUMPTIONS

PV	Capacity (MW)	MYPD 6 Date	Stress Test Date	Delay
PV Bid Window 5	75	Dec-24	Dec-25	12 Months
PV Bid Window 5	75	Jan-25	Jan-26	12 Months
PV Bid Window 5	225	Feb-25	Feb-26	12 Months
PV Bid Window 5	75	Apr-25	Oct-26	18 Months
PV Bid Window 6	270	Aug-25	Feb-27	18 Months
PV Bid Window 6	590	Sep-25	Mar-27	18 Months
PV Bid Window 6	140	Feb-26	Aug-27	18 Months
PV Bid Window 7	1800	Mar-27	Sep-28	18 Months
PV Bid Window 8	1800	Dec-27	Jun-29	18 Months

TABLE 11: OTHER IPP PROJECTIONS STRESS TEST ASSUMPTIONS.

Other	Capacity (MW)	MYPD 6 Date	Stress Test Date	Delay
Battery Storage	513	Jun-26	Dec-27	18 Months
Battery Storage	615	Nov-26	May-28	18 Months
Battery Storage	616	Apr-27	Oct-28	18 Months
Concentrated Solar Power	100	Jun-24	Jun-25	18 Months
Gas Programme	2000	Apr-28	Apr-30	24 Months

The gas programme of 2000 MW was delayed by 24 months for the purpose of the stress test which put it outside the planning horizon. Therefore, it will be completely removed from the stress test.

TABLE 12: OTHER IPP PROJECTS ASSUMPTIONS FOR STRESS TEST

Other	Capacity (MW)	MYPD 6 Date	Stress Test Date	Delay
Emergency Generation	260	Sep-24	Sep-25	12 Months
Emergency Generation	180	Jun-25	Dec-26	18 Months
Standard Offer	150	Aug-24	Aug-25	12 Months
Standard Offer	350	Jun-25	Dec-26	18 Months
Standard Offer	400	Jan-26	Jul-27	18 Months

The Emergency Generation programme is currently providing 160 MW to the system. The Emergency Generation of 260 MW and 180 MW that were expected in September 2024 and June 2025 were delayed by 12 and 18 months, respectively. Currently, the Standard Offer is not providing any capacity. It is expected that the Standard Offer of 150 MW will come online in August 2024 and followed by 350 MW (June 2025) and 400 MW (January 2026). These Standard Offer projects are delayed by 12 – 18 months to cater for the risk.

TABLE 13: RISK MITIGATION PROGRAMME ASSUMPTION FOR STRESS TEST

Risk Mitigation Programme Assumptions	Capacity (MW)	MYPD 6 Date	Stress Test Date	Delay
Risk Mitigation Programme	75	Aug-25	Feb-27	18 Months
Risk Mitigation Programme	75	Dec-25	Jun-27	18 Months
Risk Mitigation Programme	150	May-26	Nov-27	18 Months
Risk Mitigation Programme	128	Jul-26	Jan-28	18 Months

The Risk Mitigation Programme is currently providing 150 MW into the system. The upcoming projects are delayed by 18 months for stress test purposes.

Based on the stress test assumptions, Eskom OCGT's are expected to be extensively utilised in the first 3 years i.e., FY2025 (25% load factor), FY2026 (14% load factor) and FY2027 (6.9% load factor) of the planning horizon whereas with the MYPD 6 application assumptions, OCGT's were not required for more than a 6% load factor for the full period. Based on the stress tested assumptions, rotational load shedding is expected to be implemented up to FY2026. Based on these assumptions OCGT's are anticipated to run at a 6% load factor from FY2028 onwards. It is important to note that this outcome is subject to the stress tested production plan assumptions materialising and associated funding obtained to execute required maintenance.

The system EUF is projected to drop from 80% in FY2025 to 59% in FY2030 as the IPPs come online based on delayed dates and energy forecast dropping over-time. The system load factor is projected to follow the same trend.

TABLE 14: STRESS TEST PRODUCTION PLAN SUMMARY

Stress Test Summary	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Eskom OCGTs (GWh)	5236	2969	1452	1266	1266	1266
Eskom OCGTs Load Factor (%)	25	14	7	6	6	6
Load-shedding (GWh)	3952	1116	0	0	0	0

Stress Test Summary	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Stress Test System EUF (%)	80	79	76	72	67	59
Stress Test System Load Factor (%)	45	45	44	42	40	36

Although the base Production Plan for this application shows that some of the high production cost units or stations will not be utilized extensively to produce electricity to meet demand, these units or stations will be required much more, should any of the risks taken into account in the “stress test” materialise. Therefore, it is expected that these units be maintained and be kept operational through-out their approved lifespan. Effectively, these units will be a risk mitigation or insurance policy for possible changes to the environment in which Generation operates. Updated information, if applicable, will be provided during the consultation phase, prior to the revenue decision being made.

5.6 Energy losses

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

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

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

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

6 Primary Energy

6.1 Summary

The costs associated with most Eskom related primary energy elements have remained relatively static over the MYPD 6 period, with the increase mainly coming from the implementation of the carbon tax.

TABLE 15: TOTAL ESKOM PRIMARY ENERGY COSTS

Total Generation Primary Energy (Rm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Coal Usage	63 069	71 979	83 238	93 653	96 537	89 640	88 739	90 651
Water Usage	2 332	2 573	3 368	3 936	3 988	4 359	4 812	5 194
Fuel and Water Procurement department cost	274	295	334	351	368	384	401	427
Coal Handling	2 293	2 419	3 090	3 314	3 469	3 633	3 801	3 988
Water Treatment	669	848	1 004	1 014	986	1 029	1 105	1 103
Sorbent Usage	186	366	361	455	477	449	406	474
Sorbent Handling	6	17	23	23	24	20	20	20
Fuel Oil Usage	8 807	8 932	9 845	10 745	11 086	11 485	11 964	11 975
Nuclear	674	649	840	982	1 519	1 648	1 951	2 231
OCGT Usage	21 355	19 152	10 059	10 548	11 029	11 531	12 056	12 604
Coal and Gas (Gas Fired)	7	10	9	9	10	11	12	14
Environmental Levy	7 033	6 829	6 861	6 539	6 279	5 337	4 781	4 767
Carbon Tax	0	0	0	5 534	21 291	19 895	19 274	20 948
Eskom Generation Primary Energy Costs	**106 706**	**114 069**	**119 032**	**137 104**	**157 063**	**149 422**	**149 322**	**154 396**
IPP	43 534	57 662	56 236	66 633	77 640	109 820	135 510	140 943
International Purchases (Dx)	12	12	13	13	13	14	15	15
International Purchases	6 459	8 036	12 007	10 249	9 724	13 642	11 838	12 371
Ancillary Services	357	370	1 929	2 970	3 568	4 679	4 224	5 438

The total primary energy costs are captured in the table above. The costs for IPPs, international purchases and ancillary services are included in the NTCSA (Transmission) submission. Details of each element of Primary Energy will be discussed below.

6.2 Coal

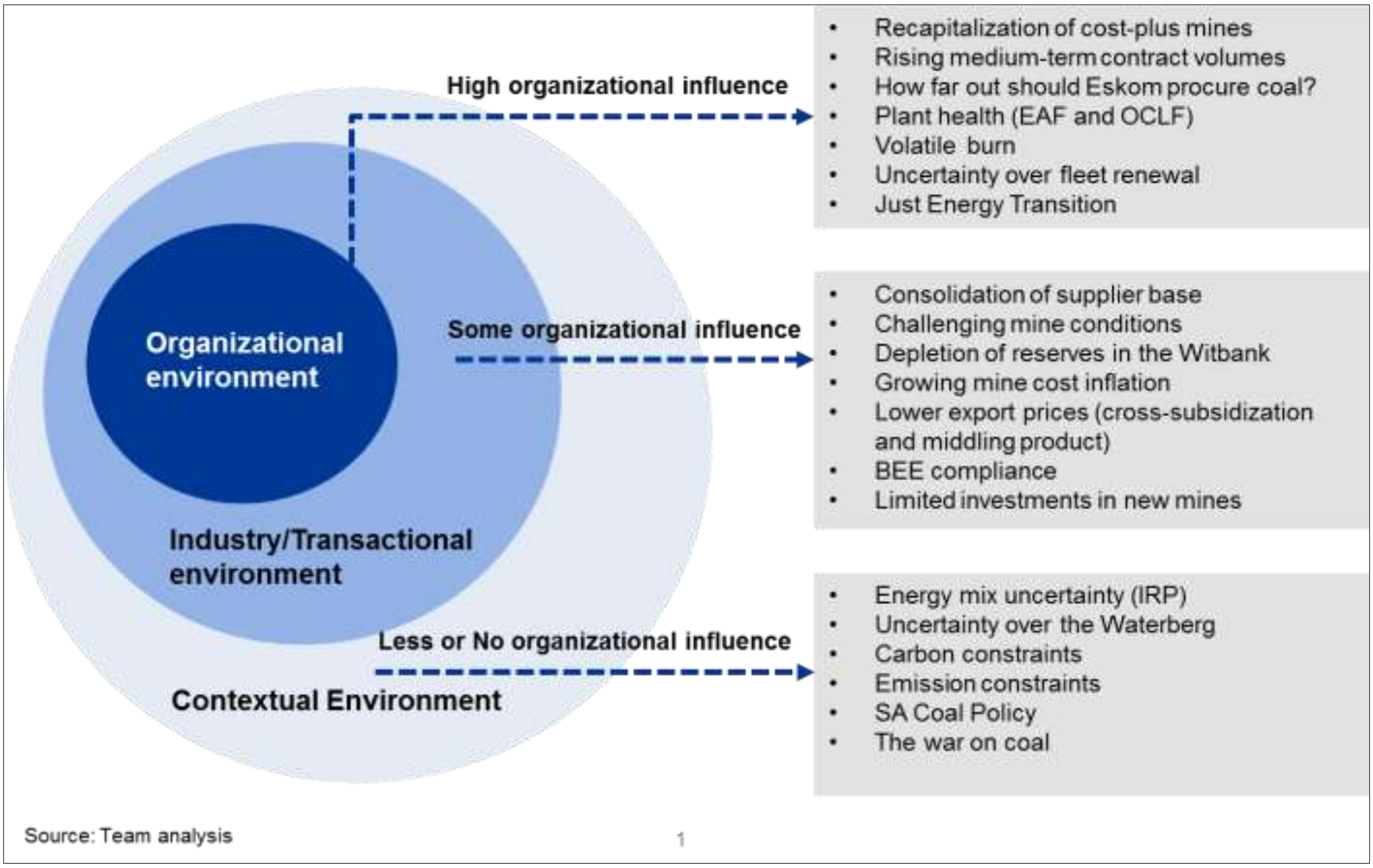
This section serves as the supporting document for Eskom's revenue application for FY2026 – FY2028. The document, however, also provides projections for FY2024 and two years of forecast data, covering the period FY2023 – FY2030.

The figure below reflects Eskom's coal value chain.

FIGURE 14: COAL VALUE CHAIN

Within each of these functional areas lies an array of factors, over which Eskom has varying degrees of influence.

FIGURE 15: CHALLENGES FACING PRIMARY ENERGY DIVISION



Eskom is exposed to various factors that have had and will continue to have implications for costs and security of primary energy supply to Eskom. Some of these factors above are discussed below.

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

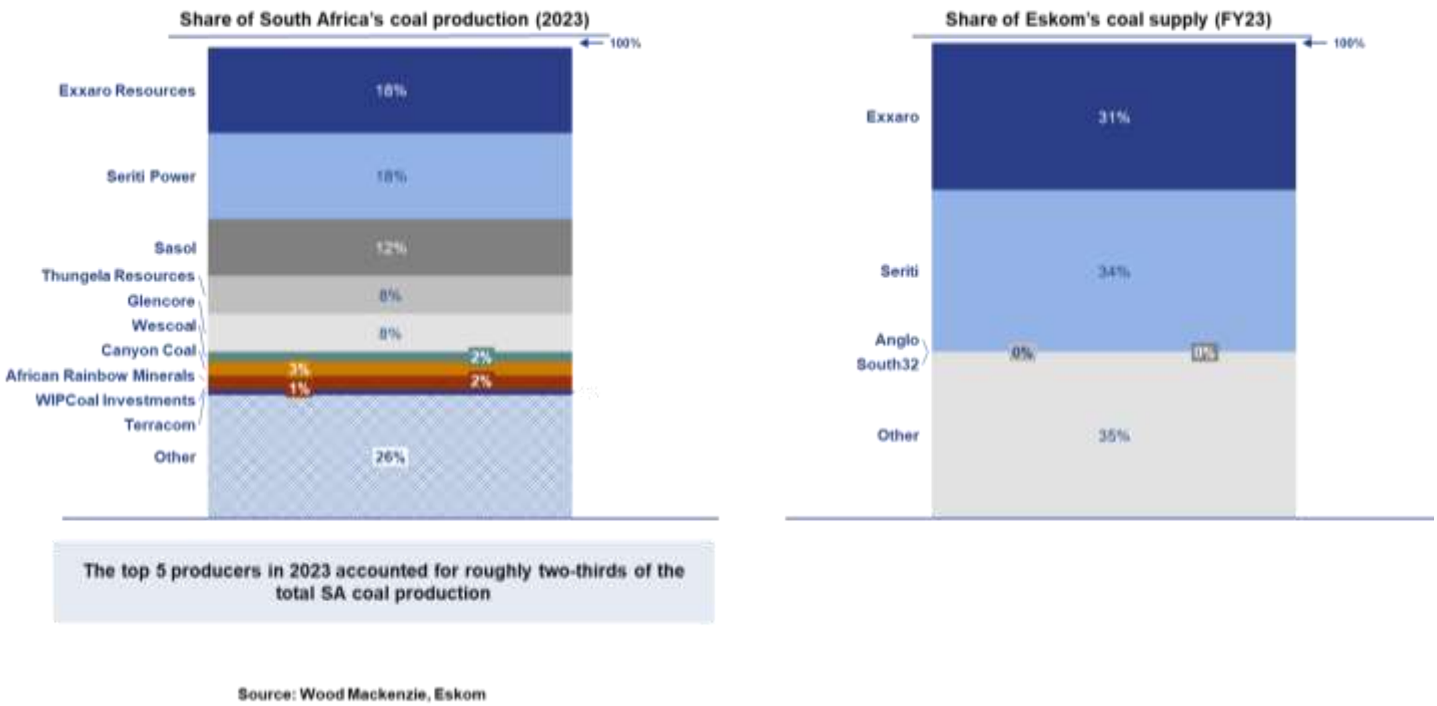
Eskom's coal supply strategy is impacted by the electricity demand forecast. This, in turn, is based on the forecast for economic growth in South Africa. After the high growth and consequent high electricity demand of 2003 – 2008, the subsequent global economic meltdown resulted in a sharp decline in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

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

6.2.2 Changing the coal industry structure

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

FIGURE 16: PRIMARY COAL PRODUCERS AND ESKOM SUPPLIERS



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

Implications of the changing industry structure include:

- Funding is a major challenge especially for smaller miners
- Lack of large scale investment into the coal mining industry which will likely create a supply shortage in the future.
- Slowdown in global and local economic growth, and the resultant decrease in export demand and pricing, increases the risk of marginal mines facing liquidity challenges. This increases Eskom's supply risk.
- Increase in export demand for a RB3 product (lower export specification product) has removed the availability of the Eskom quality middlings coal product that was previously available to Eskom.

6.2.3 Mines have an alternative market

Existing mines are taking advantage of the high export coal prices. Many investment decisions which were made at the height of the last commodity boom are now on line. However, these mines are targeting the more lucrative export market and not the domestic market. The relatively weak exchange rate also provides an incentive to earn revenue from exports. Facilitating these exports, and reducing the coal available to Eskom, are traders with export allocations at the RBCT. These traders are willing and able to buy up coal from small miners, paying cash on delivery.

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

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

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

Implications:

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

6.2.4 Deteriorating resource/reserve base

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

Implications:

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

6.2.5 Increased transport distances between mines and power stations

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

Implications:

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

6.2.6 Increasing environmental pressure

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

Implications:

- New emissions standards for power stations will necessitate higher coal quality specifications, which could, potentially, increase the cost of coal
- Similarly, any more stringent environmental legislation will increase the mine environmental, rehabilitation and closure costs, leading to higher overall prices charged to Eskom.

6.2.7 Constraints on water supplies

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

Implications:

- Increased demand will require significant investment in new water schemes, the cost of which must ultimately be recovered from both current and future users, including Eskom
- There is a need for significant investment in infrastructure to supply water to the Waterberg area, which will increase water costs and tariffs in that region
- There is a possibility that the DWS might re-price the water tariffs to reflect water scarcity in the country
- The DWS can include more water tariff components to fund infrastructure, administration and initiatives through the revision of the National Water Pricing Strategy

- As water quality from some sources declines, power stations may need to switch the source of water, which may result in additional costs. Alternatively, power stations may incur higher water treatment costs.

6.2.8 Supply constraints in key mining inputs

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

Implications:

- Continued real increases in domestic mining input and labour costs will impact all of Eskom's coal contracts as industry wide input cost changes are ultimately passed through to Eskom, since they are deemed to be beyond the control of the coal suppliers.
- Lower volumes of RB3 (Eskom quality) coal available to Eskom in the South African market.

6.2.9 Key elements of strategy to exploit and mitigate trends and market forces

6.2.9.1 Eskom Coal Strategy

In 2021, Primary Energy costs and security of coal supply have been identified as one of the major focus areas for Eskom to ensure business sustainability. A Long-Term Coal Strategy to address these focus areas has been developed. Eskom's **Long-Term Coal Strategy** has been revised to revert Eskom's coal supply to dedicated long term coal contracts for the life of the stations, with preference for conveyor delivered coal.

There are four main levers which will support the strategy objectives:

1. Investing into cost-plus mines for the life of the reserve to ensure a sustainable price path for coal stations
2. Engaging the market for long term contracts (>10 years, for the remaining life of power stations) to send a market signal for investments in untapped reserves (preferably close to power stations)

3. Strive to move coal as economically as possible, leaning more to tied colliery model delivering coal by conveyor. Rail and road transportation come second and third respectively.

4. Focus on coal quality initiatives at specific sites and provide assurance that the coal quality paid for from source is the same coal quality received

Eskom will also review its operating model for a holistic approach in implementing the strategy.

The follow items are critical to the success of the Coal Strategy:

- Eskom **tariff to be reflective** of the market price/cost of coal.
- Availability of **capital funding** for investing into existing cost plus mines.
- The **availability & access to a panel of highly skilled resources (PED specific skills)** to ensure implementation and realisation of the strategy (commodity sourcing and mining specialists, contract negotiators and specialist lawyers other related technical experts).
- (External to Eskom) **Policy and legislation** certainty, which will encourage investment in new coal mines.
- Power stations to ensure there are measurement meters in place to measure coal quality delivered at stations.
- Future production plan and parameters related to station shutdown dates and associated coal requirements must be finalised early to ensure security of supply.

Eskom’s coal supply faces four main challenges, and the strategy aims to address it through the following levers:

FIGURE 17: LEVERS TO ADRESS COAL SUPPLY CHALLENGES

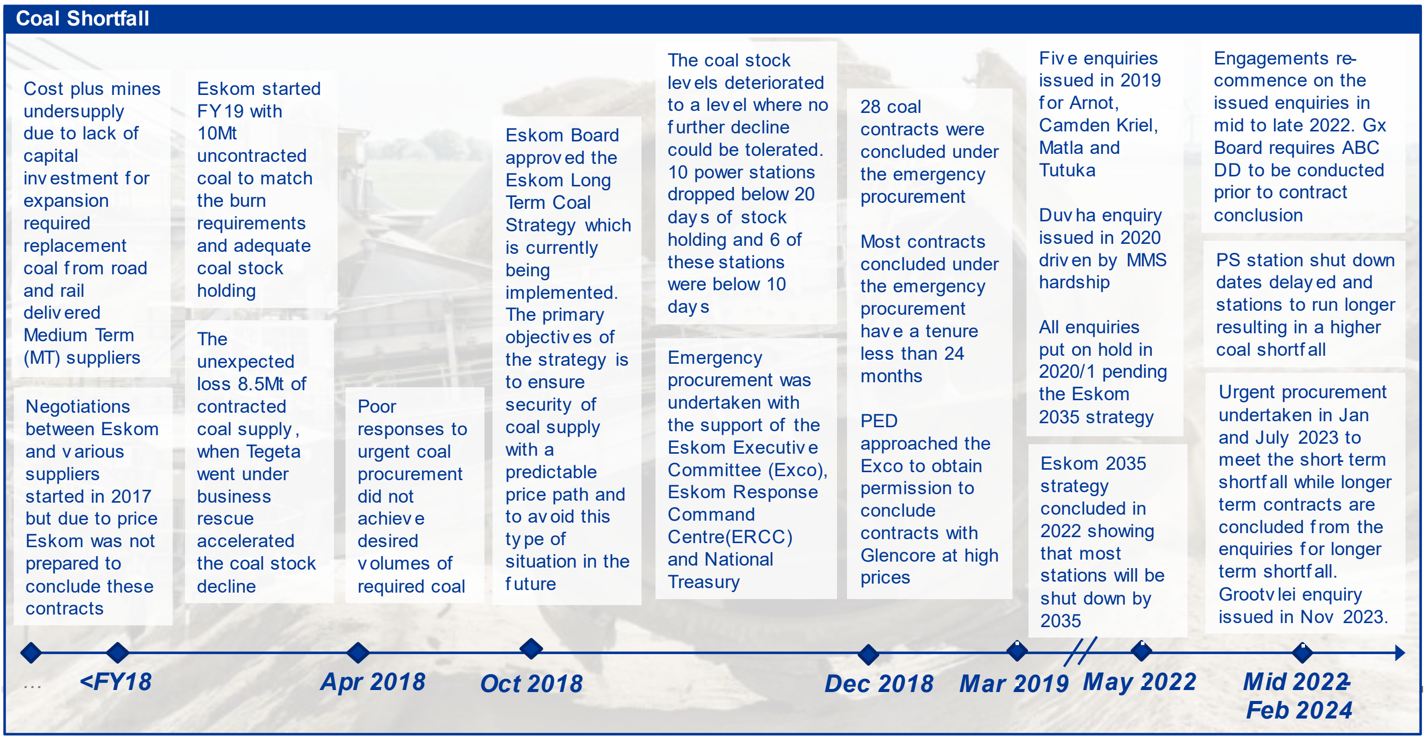
Objectives	Challenge	Impact	Levers to address challenges
The optimal cost of coal • Contribute to the lowest cost per MWh sent-out for Eskom by delivering **end-to-end cost** of (Opex and Capex) coal efficiency	1 **No new mining investment** and current mining rights not executed	Interrupts the volumes of coal mined	• Trigger new mines through expression of long term contracts (>10years)
	2 Rising **coal market price and mining costs** increase	Interrupts the volumes of coal contracted and supplied	• Cost plus investment • Production optimisation of cost plus mines • Long term contracts which hedge against price fluctuations and limits expensive logistics options
Security of coal supply • Meet **volume requirements** and safety margin on high confidence scenario with flexibility to increase	3 **Coal supply shortfall** at several power stations with contracts coming to an end	Interrupts the amount of coal stockpiled and burnt	• Cost plus contract extensions • Investment in Cost Plus mines • Long term contracting to unlock large unmined reserves (manage competition with coal exporters)
Transformation in coal procurement • Support Eskom's **socio-economic policy** objectives	4 Increased pressure and **violent protests** from local communities for localisation of Eskom procurement	Interrupts the volumes of coal transported and therefore stockpiles run low	• Transformation opportunities to be shared with stakeholders • Prioritize conveyor coal (manage road and rail supply interruption)

Historically, Eskom power stations were built on mouth of the dedicated colliery whereby coal was supplied over conveyor, the model changed in the last decade and a half.

The timeline below illustrates a high-level history of coal supply and the associated changes in the landscape, which has affected the cost of primary energy in Eskom.

Coal Security requires a multi-faceted approach, as unforeseen circumstances have caused coal shortages in the past which can be avoided going forward.

FIGURE 18: HIGH LEVEL HISTORY – COAL



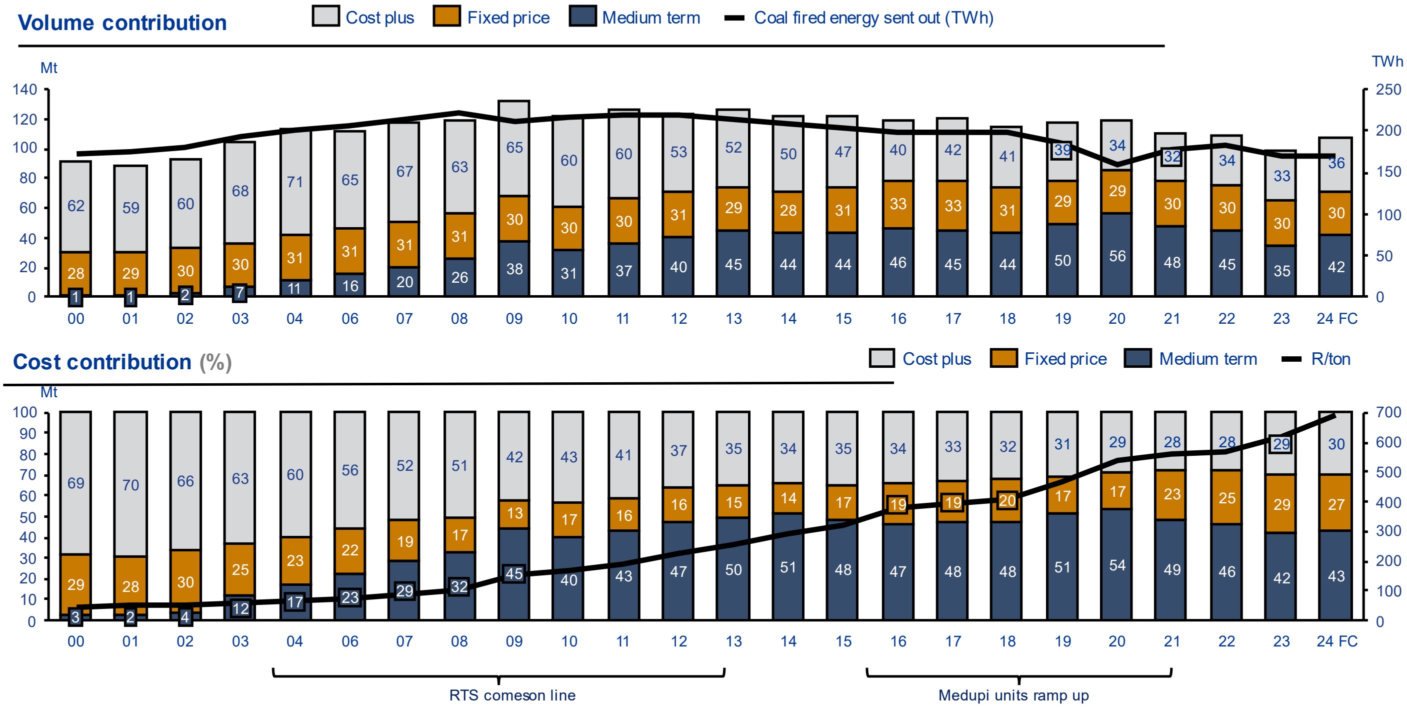
For a very similar/lower energy output historically, Eskom is producing output with a much more expensive coal supply mix mainly due to the following:

- The use of power stations with no tied colliery and a steady decrease in cost plus mine production due to a lack of investment has led to an increase in procurement on medium term contracts with additional transport cost. It is important to note that on average 30% coal costs relate to the transporting of coal when Eskom purchases coal from a non-tied mine i.e., medium term contracts.
- FY2024 – 39% **Medium term volume contributes 43%** of the coal costs. Thus, Medium term contracts are still the **most expensive coal contracts.**
- For FY2024 approx. 28% of medium-term contract coal costs relate to the transportation
- The reduced production from the cost-plus mines (volumes) and the associated inflationary fixed cost escalations at these cost-plus mines results in a higher unit cost of coal. (i.e., the fixed costs remain the same with reduced volumes)

The change in coal supply mix and the associated cost contribution are illustrated below.

For very similar energy output historically (if not even lower), Eskom is producing a similar output with a much more expensive coal supply mix.

FIGURE 19: VOLUME CONTRIBUTION AND PERCENTAGE COST CONTRIBUTION



There are four main levers to ensure the **sustainable coal cost** illustrated below.

FIGURE 20: FOUR MAIN LEVERS TO ENSURE SUSTAINABLE COAL COST

Lever	Description
Long term fixed price contracts	Apply a variety of contracting and technical levers to improve overall TCO[1] (across coal price, transport, handling, and quality) Long term contracting for remainder of power stations life will through open tender per station: • Reduce price path fluctuations (Medupi, Matimba are examples) • Trigger new investments into mining resources
Cost plus contracts	Increase value from Eskom's current contracts through improved volumes with predictable cost trajectory: • Cost plus investment to get mine back to "contractual" levels . • Business case to consider the best option between Eskom and mining house capital funding. • Cost plus contracts extension for the entire reserved and production optimisation
Increasing bargaining and negotiation power	Operating structure review around increasing the flexibility and relevance of contracting procedure Power Station specific open tender to build a catalogue of suppliers Improve the negotiation capability of PED by implementing one of the following: • Contracting in commodity procurement experts and negotiators for long term negotiations • Building capability by recruiting own commodity experts from the market • Dedicated contract lawyers
Long term coal contracting	Approval to communicate Eskom coal requirements in the following platforms: • Conferences • Mining related publications • Hosting supplier engagement forums • Enter into talks with investors for mine investment with guaranteed off takes, to ensure correct ramp up periods post open tender per power station

6.2.10 Key Assumptions underlying the Primary Energy sourcing plans and cost forecasts

The key assumptions underlying the primary energy sourcing plans and cost forecasts are detailed below:

6.2.10.1 Coal sources and volumes

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

6.2.10.2 Coal costs and price escalations

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

6.2.10.3 Water

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

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

6.2.10.4 Logistics

- Coal to Grootvlei and Majuba, with access to sidings, is planned on rail.
- All ST/MT contracts are on a Delivered basis.

6.2.11 Key drivers affecting increase in coal cost forecast

6.2.11.1 Uncertain energy plans

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

6.2.11.2 Logistics

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

6.2.11.3 Cost plus mine production

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

6.2.11.4 Mining costs

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

6.2.11.5 Water

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

6.2.11.6 Sorbent

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

6.2.11.7 Stricter Environmental Legislation

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

6.2.12 Key opportunities and challenges

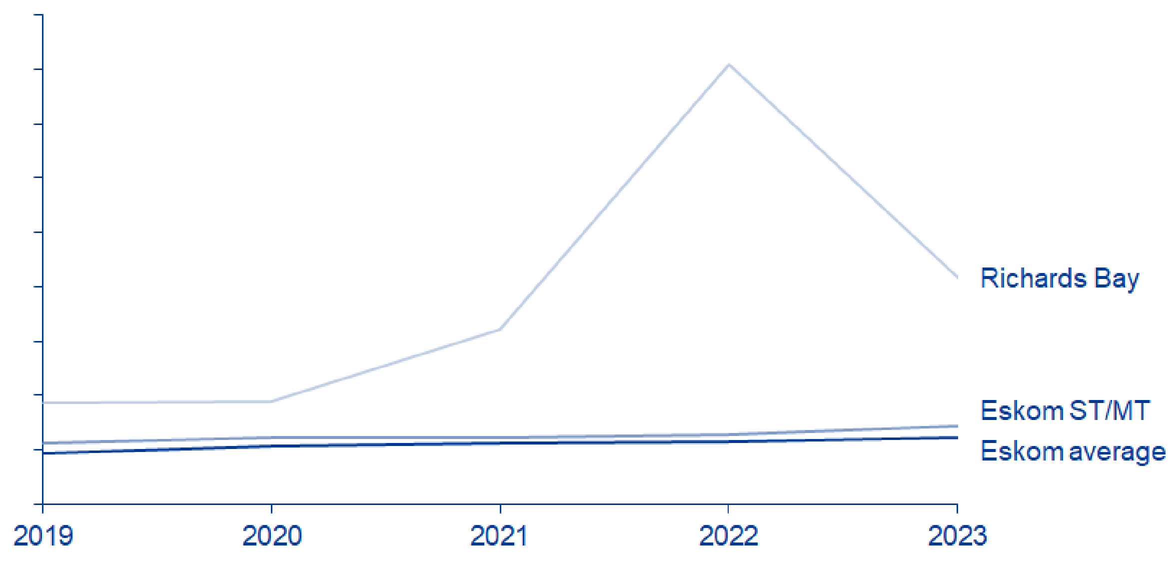
- The South African coal market still requires substantial investment and recapitalisation to meet both domestic and export coal requirements. More suppliers are needed to improve the competitiveness and responses to requests for proposals for coal. The current economic environment is not conducive to investment.

- Eskom's financial position and the limitations on borrowings create a difficult environment for Eskom to raise capital for further investment in maintaining existing cost-plus coal mining operations.
- Funding within the coal environment remains a substantial challenge for new and established miners, as lenders look for opportunities in the clean energy space.

6.2.13 Benchmarking

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

FIGURE 21: AVERAGE STEAM COAL PRICES(R/T)



Sources:

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

Eskom PED

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

6.2.14 Coal supply to meet coal burn requirements

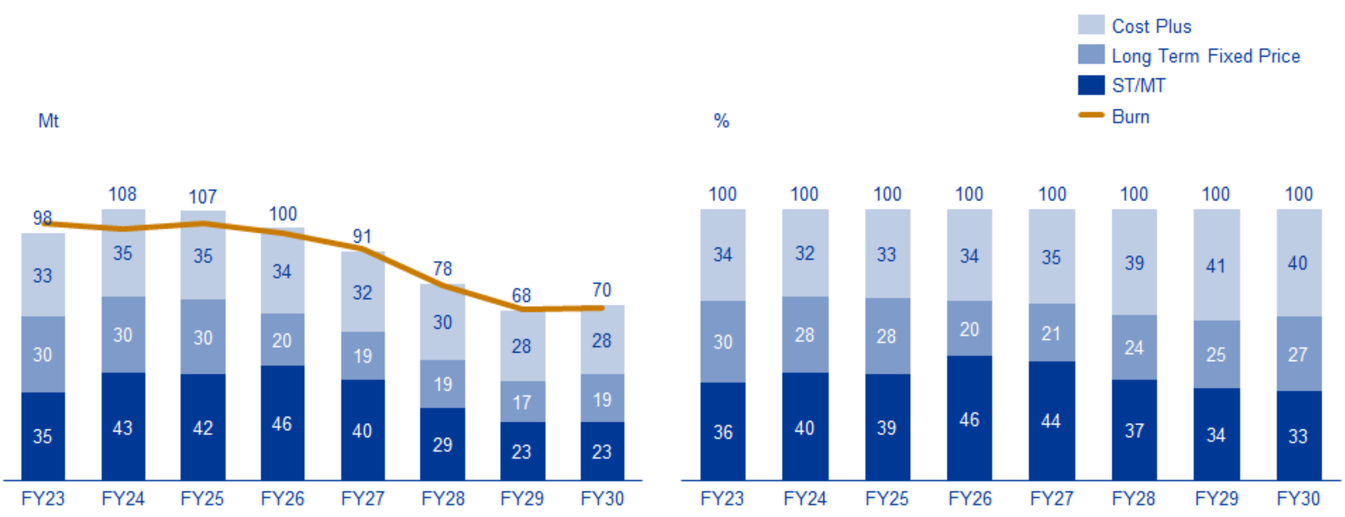
6.2.14.1 Coal Volumes

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

While gross electricity generation remains relatively steady, Eskom's share of total electricity generation also declines over this period. There is an average annual decrease in coal fired electricity generation of 3% from FY2024 – FY2028.

Historically, long term coal supply contracts have proved to be cheaper sources of coal, in addition to providing a secure supply of coal for Eskom. It is Eskom's policy, where possible, to secure long term contracts with coal sources that are close to power station. Shorter duration contracts and a small percentage of uncontracted coal provide the flexibility to bridge short term changes in demand. The figure below reflects the volume of coal forecast to be procured over the FY2025 – FY2030 period. The proportion of coal from the cost plus mines assumes that Eskom will extend the cost plus contracts and invest in the cost plus mines. Coal from long term Cost Plus and Fixed Price contracts increases from 61% in FY2025 to 63% in FY2028, while coal from STMT contracts and uncontracted coal decreases from 39% to 37% over the same period.

FIGURE 22: COAL PURCHASES VOLUMES



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

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

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

6.2.14.1.1 COST PLUS MINES

The volume of coal declines from 35Mt in FY2025 to 30Mt in FY2028.

TABLE 16: COST PLUS MINE PRODUCTION (MTONS)

Volumes (Mt)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Kriel	3.30	3.74	3.91	4.20	4.00	4.00	4.00	4.00
Lethabo	13.61	14.73	14.00	11.42	10.09	8.19	8.16	7.33
Tutuka	3.37	3.45	4.00	4.00	4.00	4.00	1.50	1.00
Matla	6.06	5.33	4.70	5.85	5.44	5.85	5.85	7.07
Kendal	6.81	7.72	8.49	8.55	8.35	8.35	8.36	8.31
Total	**33.15**	**34.98**	**35.10**	**34.02**	**31.88**	**30.39**	**27.87**	**27.71**

The main reason for the decline is because production from New Vaal (Lethabo Power Station) and New Denmark Collieries (Tutuka Power Station) declines as the mines age and as the burn requirement at Tutuka Power Station declines. Coal for Matla Power Station is still planned under the cost plus contracts while Eskom and Exxaro are negotiating a new contract for Matla.

6.2.14.1.2 LONG TERM FIXED PRICE MINES

TABLE 17: LONG TERM FIXED PRICE CONTRACTS (MTONS)

Volumes (Mt)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Duvha (MMS)	5.10	7.18	4.73	-	-	-	-	-
Matimba (Grootgeluk)	13.13	11.67	13.57	10.33	10.18	10.29	8.97	9.41
Medupi (Grootegeluk)	11.78	11.44	11.72	10.13	9.01	8.69	7.76	9.83
Total	**30.01**	**30.29**	**30.02**	**20.46**	**19.19**	**18.98**	**16.72**	**19.24**

Total production declines after FY2025 when the MMS contract expires. The contract with South32/Seriti Power was renegotiated until the end of 2024. Coal for Duvha is planned under the STMT contracts thereafter. Production from Grootegeluk mine is matched to the burn requirements at Matimba and Medupi Power Stations. This plan makes provision for coal to be moved from the Medupi stockyard to power stations in Mpumalanga.

6.2.14.1.3 SHORT/MEDIUM TERM (STMT) AND UNCONTRACTED COAL

Coal is procured on STMT contracts to meet coal burn requirements that cannot be fulfilled by long term contracts. All coal for Arnot, Camden, Grootvlei, Hendrina and Majuba Power Stations is procured on STMT contracts, as these stations do not have dedicated long-term contracts. All coal for Duvha post FY2025 is also planned on STMT contracts, which results in an increase in coal from this contract category in FY2026. Thereafter, total volumes decline as Eskom electricity generation declines, specifically from coal fired power stations.

TABLE 18: SHORT TERM/MEDIUM TERM AND UNCONTRACTED COAL (MTONS)

Volumes (Mt)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Arnot	3.89	5.58	4.49	5.34	3.86	3.47	2.43	3.15
Kriel	2.86	2.58	2.70	2.20	1.36	1.24	0.25	-
Lethabo	0.16	0.86	-	-	-	-	-	-
Tutuka	0.09	1.90	0.90	2.16	0.97	-	-	-
Matla	3.30	3.77	4.42	2.68	1.83	1.25	-	-
Hendrina	1.37	2.28	2.69	2.69	1.34	0.83	0.79	1.03
Duvha	-	0.86	0.56	5.40	4.90	3.70	3.20	1.80
Kendal	2.66	1.13	-	0.87	1.50	-	-	-
Majuba	10.13	11.28	10.41	8.10	8.91	6.23	5.52	5.49
Matimba	-							
Camden	4.21	4.88	3.60	3.02	2.75	0.72	0.75	0.90
Komati	0.18	-	-	-	-	-	-	-
Grootvlei	1.51	1.70	1.74	1.24	0.60	0.60	0.60	0.97

Volumes (Mt)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Medupi	-							
Kusile	4.89	5.98	10.59	12.23	12.17	10.83	9.46	9.69
Total	**35.26**	**42.81**	**42.10**	**45.92**	**40.20**	**28.87**	**22.99**	**23.02**

6.2.14.1.4 UNCONTRACTED COAL

The STMT coal volumes include coal that is not yet contracted, and the sources of which are also not yet known. This coal follows a similar trend as the STMT coal, first increasing and then declining as coal burn requirements decline.

TABLE 19: UNCONTRACTED COAL (MT)

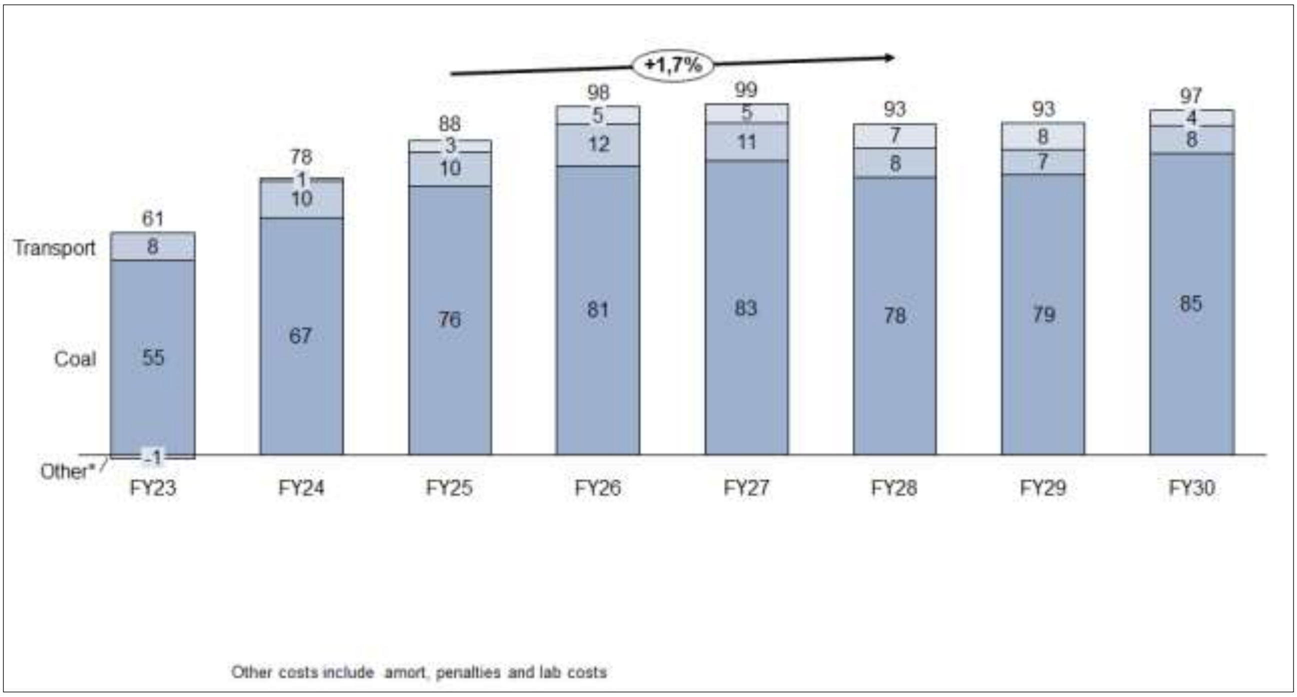
Volumes (Mt)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Uncontracted & Unknown	-	-	13.28	16.36	17.45	9.34	8.02	8.83

Having a proportion of coal uncontracted gives Eskom the flexibility to deal with changes in electricity demand. However, there are still drivers, e.g., lower electricity demand from industrial users because of lower economic growth or lower international commodity prices, that can result in Eskom not being able to offtake some coal that has been contracted. In this plan, the decrease in electricity demand, and the more material decrease in Eskom generation, has resulted in a provision for take or pay penalties.

6.2.14.2 Coal Purchases Costs

Eskom's forecasted spend on coal over the three years, FY2026 – FY2028, is R289 bn. The total cost of coal purchased from FY2025 – FY2028 increases by an annual average of 1.7% during the MYPD 6 period.

FIGURE 23: COAL PURCHASES COSTS (R'BN)



The unit cost (R/t) increases by an average annual rate of 13% over the FY2025 – FY2028 period, primarily due to the decrease in volumes from the cost plus mines and the increase in the cost of coal from Grootegeluk mine.

Transport costs have been included to move excess coal from Medupi Power Station to stations in Mpumalanga. The decrease in generation from coal fired plant has resulted in take or pay provisions for coal, mostly at Kusile Power Station, which cannot be burnt elsewhere because the qualities are incompatible.

6.2.14.3 Logistics

Coal is transported from the source to a power station by conveyor, road (truck), rail or a combination of road and rail.

- **Conveyor** – this is the mode used for mines located close to the power station. It is usually the cheapest way to transport coal to the station.
- **Road** – coal is trucked to its destination when a conveyor or rail option is not feasible.
- **Rail** – in the absence of a conveyor, rail is the preferred option. It is a safer option than road and reduces the wear and tear on roads. However, it is dependent on Transnet's performance, the infrastructure at power stations and the mines' distance to a rail siding. Presently, only Majuba and Tutuka have the infrastructure for coal to be railed directly to the power stations. In this submission, only coal to Majuba is assumed to be on rail. Coal

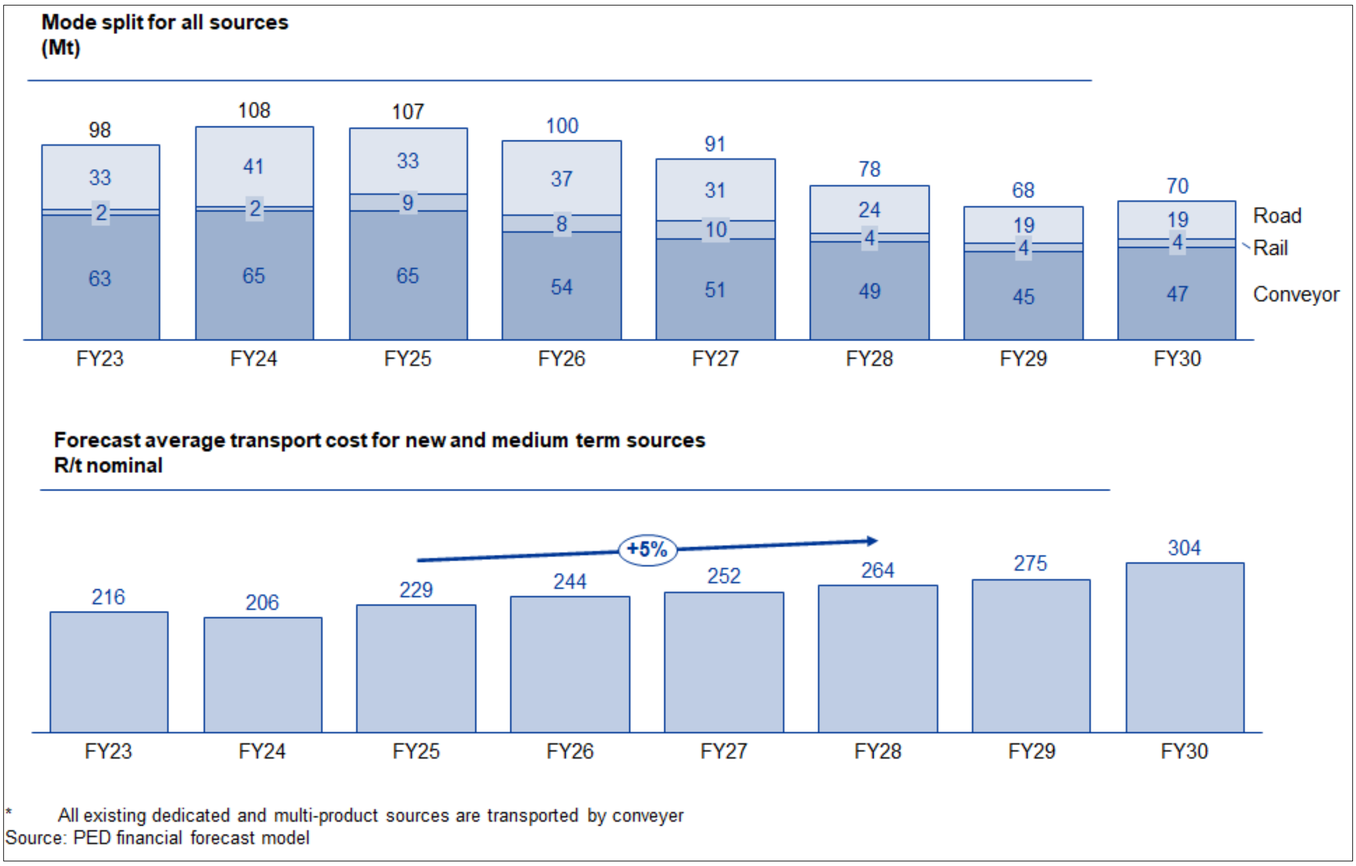
for which sources are unknown is assumed to be on road. Camden and Grootvlei are located close to rail sidings, so it is possible to rail the coal to the sidings and then transport it by truck to the power stations, but the infrastructure needs to be refurbished.

Most mines need to truck coal to a siding because most mines do not have rail sidings on site. The coal is loaded onto a train at the siding, then railed to a power station or another siding, from where it is again loaded onto trucks to be transported to a power station. This multi-modal form of transport adds to the cost of coal and can result in the cost of rail exceeding the cost of road transport.

The cost of rail is subject to tariffs determined by Transnet. The determination has not been a transparent process historically, and Eskom does not have much leverage to negotiate as Transnet is the only rail service provider at present. Annual increases in the tariffs have been higher than inflation historically. This trend looks set to continue as Transnet seeks to re-capitalise, re-establish operations and become profitable once again. Transnet tariffs are not regulated.

The figure below reflects the volume of coal per transport mode and the average unit transport cost of coal transported by road and rail. The proportion of coal on conveyor increases from 61% in FY2025 to 63% in FY2028 as total coal purchases decreases.

FIGURE 24: FORECAST LOGISTICS MODES AND COSTS FOR COAL (MTONS)



The average annual cost of getting a tonne of coal to a power station increases by 5% over the FY2025 to FY2028 period. The average rate is impacted by the mix of road and rail volumes. Coal transported by rail may also have a road component to get the coal to and from a rail siding.

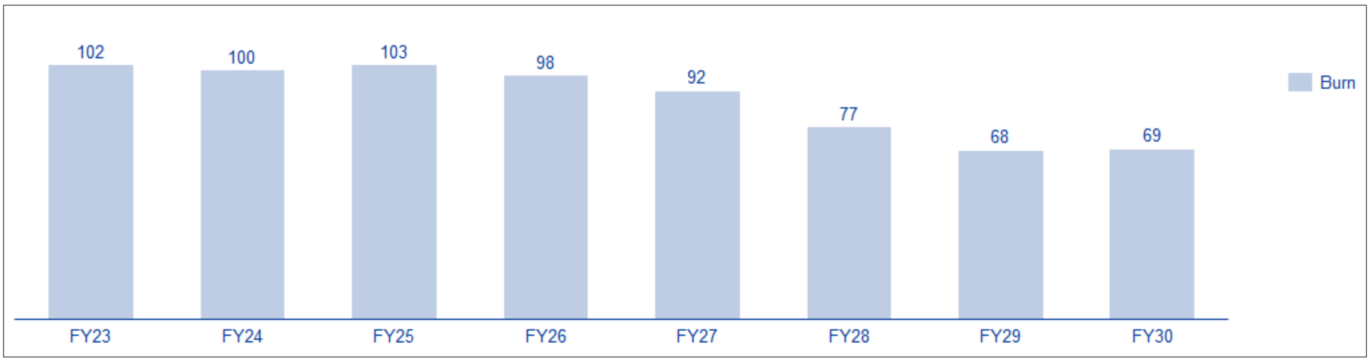
6.2.15 Coal Burn requirements

6.2.15.1 Coal Burn Volumes

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

While gross electricity generation remains relatively steady, Eskom's share of total electricity generation declines by an annual average of 7.8% from FY2025 – FY2028. There is an average annual decrease in coal fired electricity generation of 8.9% from FY2025 – FY2028. Consequently, there is a decline in coal volumes burnt, as illustrated in Figure below.

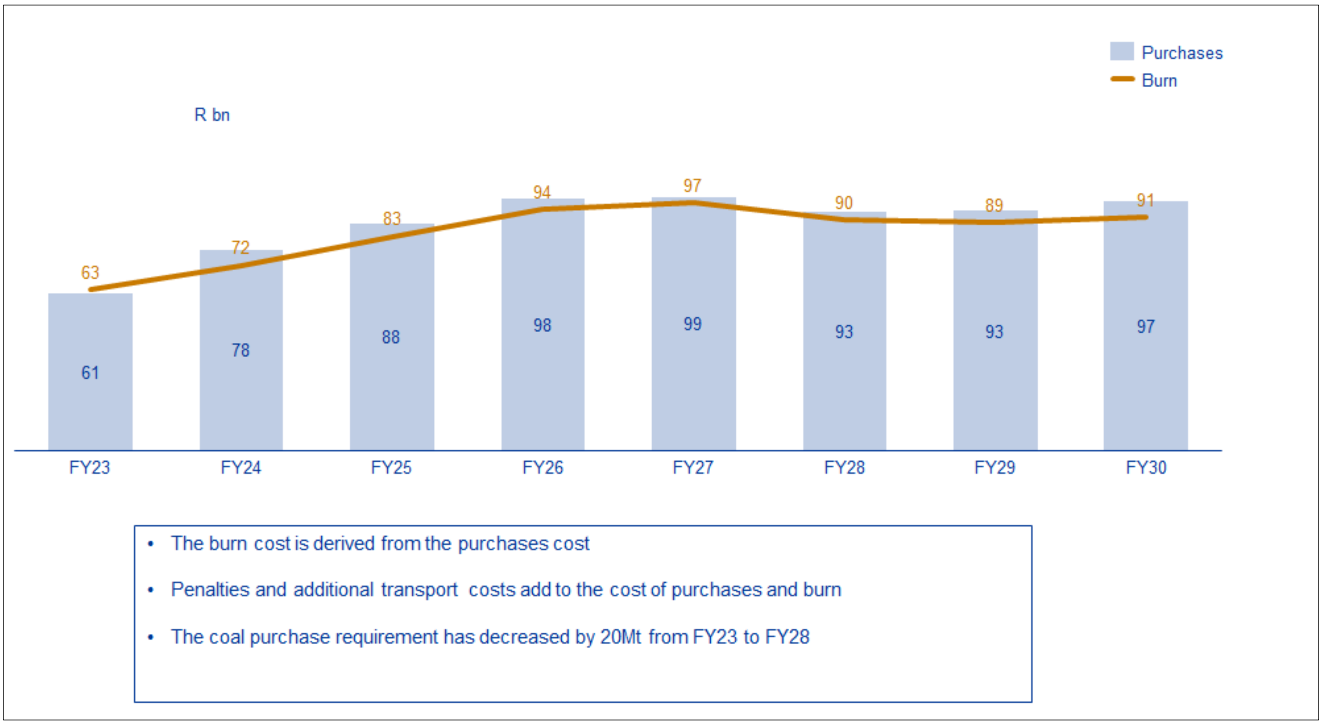
FIGURE 25: COAL BURN VOLUMES (MTONS)



6.2.15.2 Coal Burn Costs

Coal burn costs are derived from coal purchases costs. Coal burn costs increase from R83bn in FY2025 to R97bn in FY2027 before decreasing to R90bn in FY2028. This follows the same trajectory as the coal purchases costs.

FIGURE 26: COAL BURN PROJECTIONS (R'BN)



The annual changes in the burn cost comprise price, volume and other smaller variances (efficiency and mix). The price variances make up the largest part of the year-on-year variances, followed by the volume variances.

- **Price variances:**

The price variances at power stations are caused by the following:

Lethabo:

Declining burn and production at a Cost Plus mine results in a higher unit cost because most of the costs are fixed.

Duvha:

The current long-term contract ends in FY25. Post this period, coal is planned under the STMT category, which is more expensive.

Matimba and Medupi:

The decreasing burn requirement has resulted in lower offtake levels and a higher R/ton unit cost.

Majuba:

Majuba does not have any long-term contracts. As the STMT contracts expire, new contracts must be concluded. In FY2027, the uncontracted coal, for which the sources are unknown currently, is significantly higher than in FY2026. Because of the uncertainty about the sources, this coal is planned at a higher price.

Kusile:

The burn requirement at Kusile Power Station is lower than coal volumes already contracted. This coal cannot be used at other power stations because the quality is unsuitable. Therefore, take or pay payments have been provided for in FY2026 – FY2028.

- **Volume variances:**

The positive volume variances reflect the lower burn requirement as a result of lower generation from the coal fired stations.

- **Other variances:**

The mix variance refers to the way the power station fleet is utilised. This is impacted by various factors, e.g., maintenance, minimum generation requirements, grid stability and fuel cost. Efficiency refers to the rate at which the station consumes fuel. These variances are relatively small.

6.2.15.3 Stock Management over the MYPD 6 period

Stock is maintained at each power station to manage the risk of the power station running out of coal. The volume of stock depends on the station coal burn, the lead time to procure coal and whether the station has a dedicated mine. In some instances, e.g., at Medupi and Kusile, unexpected changes in electricity generation results in large coal stockpiles being built up. The delays in completion of Medupi and Kusile, as well as the unit 4 explosion at Medupi in 2021, the fire at Kusile's unit 5 in 2022 and the collapse of the flue duct at Kusile in 2022, exacerbated the coal stock build up.

Generation calculates the closing stock of coal (cost and volume) as follows:

(Opening stock [Cost and Volume] + Purchases [Cost and Volume]) – Burn [Cost and Volume]

An example is provided in the table below. *Note that the values and volumes are only examples for illustration purposes and not actual values*.

TABLE 20: EXAMPLE OF A COAL STOCK CALCULATION

EXAMPLE	FY01	FY02	FY03	FY04	FY05	FY06	FY07
Opening stock:							
Mtons	34.91	45.40	42.21	41.78	41.88	40.24	40.07
Rands (bn)	16.82	12.95	11.04	11.51	12.69	13.55	15.06
R/ton	481.96	285.22	261.66	275.37	302.96	336.75	375.90
PLUS							
Purchases:							
Mtons	112.57	101.37	98.69	95.91	88.29	81.98	77.97
Rands (bn)	25.24	25.45	27.75	30.21	31.15	32.39	34.51
R/ton	224.20	251.10	281.24	314.99	352.78	395.12	442.53
MINUS							
Burn:							
Mtons	102.07	104.57	99.11	95.81	89.94	82.14	77.12
Rands (bn)	29.11	27.36	27.29	29.03	30.29	30.88	32.38
R/ton	285.22	261.66	275.37	302.96	336.75	375.90	419.91
IS EQUAL TO							
Closing stock:							
Mtons	45.40	42.21	41.78	41.88	40.24	40.07	40.93
Rands (bn)	12.95	11.04	11.51	12.69	13.55	15.06	17.19
R/ton	285.22	261.66	275.37	302.96	336.75	375.90	419.91

Note: This table is an example with fictitious figures for illustration

Total coal stock days at the end of FY2025 are forecast to be 82 days. System stock days remain around 84 days over the MYPD 6 period.

TABLE 21: FORECAST COAL STOCK DAYS

Coal Stock days	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Arnot	21	40	51	78	68	63	44	51
Kriel	22	35	47	63	64	64	67	71
Lethabo	24	35	34	54	54	54	54	60
Tutuka	25	45	45	45	45	45	45	48
Hendrina	18	43	52	52	50	52	53	77
Matla	26	38	53	63	63	65	71	99
Duvha	25	66	67	66	65	66	68	63
Kendal	53	68	38	52	55	62	79	107
Majuba	28	40	79	78	76	81	81	69

Coal Stock days	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Matimba	43	47	47	47	47	47	47	44
Camden	16	40	43	47	54	47	48	54
Grootvlei	19	29	43	43	42	42	39	100
Komati	-							
Medupi	409	497	445	391	367	344	321	238
Kusile	30	28	34	28	29	29	32	35
TOTAL	**65**	**80**	**82**	**84**	**83**	**84**	**84**	**84**

- Arnot's coal is fully contracted until FY2026. Changes in the burn requirement will be reflected in the stock levels. Post FY2026, purchases decrease in line with burn and stock levels decrease.

- Lethabo's burn is limited because of emissions constraints. The mine is a cost plus mine, so it does not make sense to limit production.

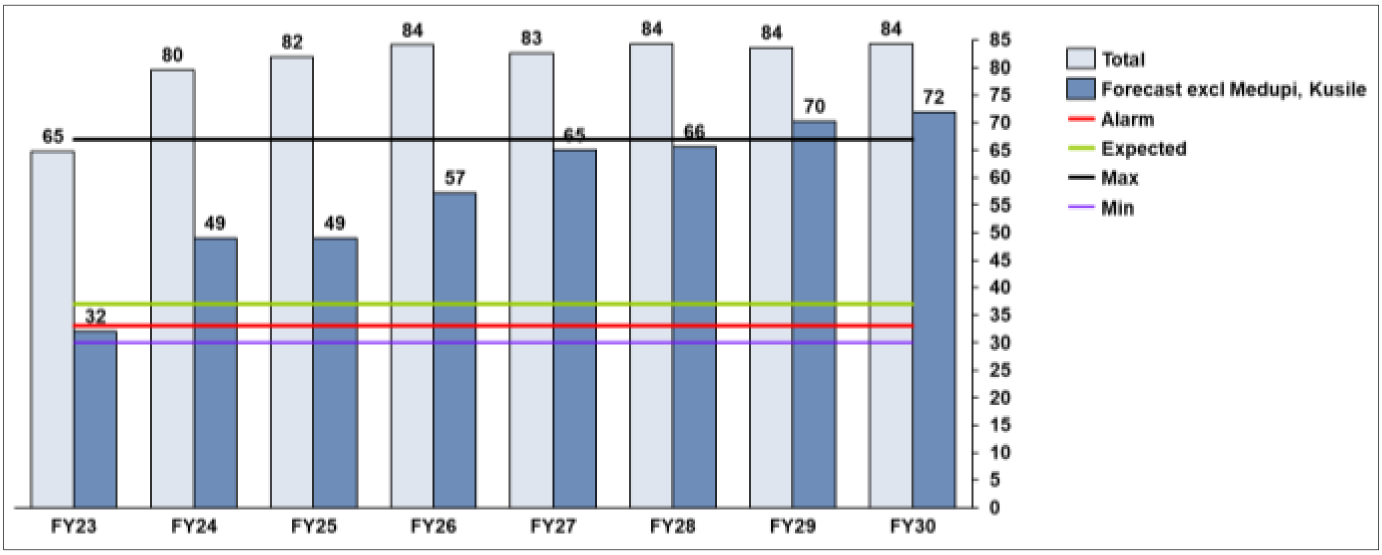
- Hendrina and Duvha purchases have been matched to the burn. Stock levels remain largely consistent, although they are relatively high.

- Medupi and Matimba have coal contracts with Exxaro that include a take or pay clause. Historically, all coal that could be burnt or stockpiled was taken to reduce the take or pay payments. Now that the burn at these stations is planned to be lower than was expected, it is not possible to reduce stock levels significantly. Additionally, the impact of the construction delays at Medupi continues to be seen. Eskom has provided for moving some of the coal to other stations during this MYPD6 period to prevent an increase in the stock levels.

- Electricity generation at Camden and Grootvlei Power Stations declines from FY2026. Accordingly, the standard daily burn volumes have been reduced. However, coal that is already contracted has been included in the purchases and stock at these stations. The result is that stock levels do not decline in line with production.

The graph below illustrates what happens to the stock days if the stock for Medupi Power Station is removed. Then system stock days fall below maximum levels until FY2028, but the issues discussed above still result in stock levels remaining relatively high.

FIGURE 27: FORECAST SYSTEM COAL STOCK DAYS



Where possible, Eskom will implement measures to bring and maintain stock days at expected levels:

- Modify coal supply agreements to minimise coal volumes, where feasible.
- Reallocate excess stock to stations that have the capacity to receive and use or stock it.

The table below, reflects the stock volumes of the coal stations.

TABLE 22: FORECAST COAL STOCK VOLUMES (KTONS)

Coal Stock Volumes	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Arnot	479	926	1 194	1 828	1 604	1 475	1 029	1 274
Kriel	706	1 136	1 524	2 059	2 089	2 105	2 176	2 005
Lethabo	1 091	1 641	1 661	2 661	2 661	2 661	2 661	2 661
Tutuka	1 056	2 345	2 341	2 278	2 548	3 973	3 753	2 894
Hendrina	250	527	730	736	703	732	746	1 018
Matla	950	1 537	2 130	2 513	2 542	2 603	2 841	4 404
Duvha	819	2 197	2 229	2 212	2 190	2 197	2 268	2 187
Kendal	2 624	3 066	1 772	2 399	2 546	2 852	3 629	4 714
Majuba	1 102	1 787	3 582	3 556	3 481	3 701	3 697	3 432
Matimba	1 800	2 080	2 080	2 080	2 080	2 080	2 080	2 080
Camden	263	532	733	804	913	797	811	958
Grootvlei	138	205	305	305	293	298	275	639
Komati	0	0	0	0	0	0	0	0
Medupi	17 452	17 720	17 720	16 720	15 720	14 720	13 720	12 720
Kusile	996	1 070	1 496	1 494	1 531	1 543	1 716	1 739
TOTAL	**29 726**	**36 770**	**39 496**	**41 645**	**40 901**	**41 736**	**41 402**	**42 724**

The stock volumes translate into the following stock values.

TABLE 23: FORECAST COAL STOCK VALUES (R'BN)

Coal Stock Values (R'bn)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Arnot	347	730	1 014	1 614	1 559	1 716	1 218	1 705
Kriel	567	895	1 675	2 396	2 661	2 645	2 969	2 907
Lethabo	397	627	700	1 517	1 847	2 410	2 613	3 000
Tutuka	1 115	2 387	2 692	2 618	3 166	5 313	8 086	9 290
Hendrina	207	437	710	777	784	829	888	1 299
Matla	745	1 454	2 975	3 318	3 575	3 685	4 286	5 828
Duvha	569	1 602	1 695	2 531	2 752	2 691	2 941	3 175
Kendal	1 710	2 160	1 372	2 083	2 415	2 481	3 332	4 620
Majuba	862	1 382	3 342	4 250	5 506	6 888	7 962	8 762
Matimba	383	522	522	522	522	522	522	522
Camden	198	602	625	838	718	964	1 192	1 591
Grootvlei	118	185	382	410	417	450	444	1 106
Komati	-0	-0	-0	-0	-0	-0	-0	-0
Medupi	6 648	6 796	6 796	5 835	4 654	3 319	1 683	275
Kusile	613	663	1 157	1 269	1 395	1 439	1 720	1 841
TOTAL	**14 480**	**20 442**	**25 657**	**29 979**	**31 971**	**35 353**	**39 857**	**45 923**

It is necessary to hold stock to manage changes in supply and demand. As with most risk mitigation measures, the cost one is willing to pay depends on the risk level one is willing to accept. Generation is the primary supplier of electricity in South Africa. The cost of not being able to generate far exceeds the cost of stockpiling coal. Nevertheless, Generation is very mindful of the cost to the consumer and attempts to manage coal stock levels to minimise this cost while reducing the risk of stockouts. In certain circumstances, such as at Medupi Power Station, stock levels do inevitably exceed optimal levels. However, these are specific instances, rather than the norm.

6.3 Water usage costs

TABLE 24: GENERATION RAW WATER COSTS (EXISTING AND NEW INFRASTRUCTURE)

Water Usage Costs (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Coal Stations	2 236	2 476	3 268	3 825	3 868	4 229	4 681	5 063
Koeberg	5	5	7	8	8	8	8	8
Peaking	90	91	92	100	110	120	120	120
Renewables	0	0	0	2	2	3	3	3
Other	1	0	1	1	0	-	-	-
Total	**2 332**	**2 573**	**3 368**	**3 936**	**3 988**	**4 359**	**4 812**	**5 194**

Eskom pays for the water it consumes through a series of water tariffs. These are legislated, so Eskom has no control over the tariffs. Historically, water costs have been very low as a percentage of the Eskom operating costs. The main reason for this is that the water infrastructure assets (Eskom's and that of DWS) were constructed several years ago and are almost completely depreciated. As new infrastructure and water charges have been introduced, the demand for water and the cost have increased. Furthermore, the cost increases as the distances over which water needs to be transferred increase and as new tariffs are introduced into legislation. There is a possibility that the DWS might re-price the water tariffs to reflect water scarcity in the country, which will be reflected in the revised National Water Pricing Strategy

Generation's power stations receive water supply from various schemes and through various contracts.

TABLE 25: SCHEMES AND POWER STATIONS

Scheme	Power Stations Supplied	Water Tariff Components
Vaal River Eastern Sub System (VRESS)		
Komati Water Scheme	*Duvha (approx. 50%), Komati, Hendrina, Arnot & Kusile*	*Catchment Management Fee (CMF); Water Research Commission (WRC); VRESSAP & KWSAP*
Usutu Water Scheme	*Kriel (approx.40%) & Camden*	*Return on Assets (ROA); CMF; WRC; VRESSAP; Operations & Maintenance (O&M)*
Usutu-Vaal Water Scheme	*Tutuka, Matla, Kendal, Kusile, Kriel, (approx. 60%), Duvha (approx. 50%), Matla, Kendal, Tutuka & Kusile*	*ROA; CMF; WRC; VRESSAP; VRT; O&M*
Slang	*Majuba*	*CMF; WRC; VRT; VRESSAP*
Vaal	Lethabo, Grootvlei	ROA; CMF; WRC; VRT
Mokol	Matimba & Medupi Power Stations	Contract with Exxaro

The Vaal River Eastern Sub System Augmentation Project (VRESSAP) supports the entire VRESS. Hence, all the power stations currently on the VRESS scheme bear the additional cost of VRESSAP.

The Komati Water Scheme Augmentation Project (KWSAP) was commissioned to support the demand for water on the Komati Water Scheme. Therefore, all power stations supplied from or to be supplied from (e.g., Kusile Power Station) the Komati Water Scheme, attract this tariff.

The first phase of the Mokolo Crocodile West Augmentation Project (MCWAP1) was commissioned in 2015 and provides water to Medupi Power Station. The second phase of this project is expected to be commissioned after 2027. Generation and other users will be levied with a system tariff (MCWAP1 and 2). The water for Mokolo system augmentation is sourced from return flows from the Vaal River System.

Recent water infrastructure includes augmentation to the Vaal, Komati and Mokolo water schemes. The DWS National Water Pricing Strategy allows DWS to implement these projects "off budget" and to recover associated costs via a tariff. The Komati and Mokolo costs are recovered on a take or pay pricing basis. All new infrastructure will be developed and financed by the DWS. The costs will be recovered through the water tariffs. Any under recoveries due to the actual water demand being below the projected demand during the project feasibility stage will be recovered in the following year.

6.3.1 Drivers of Water usage Cost

The water financial plan comprises the following cost elements:

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

(i) Current Water Tariffs

The components of the current water tariff are:

- Capital Unit Charge (CUC) which comprises a return on assets and (ROA) depreciation
- Water Research Commission (WRC)
- Catchment Management Fee (CMF)
- Operating and maintenance cost (O&M)

(ii) Illegal abstractions

Unlawful and unaccounted water usage results in higher water tariffs payable by billed consumers. Furthermore, this will also trigger further augmentation schemes to meet demand, and thus increase water tariffs.

(iii) Current Water Demands

Electricity is a pass-through cost to Generation on the Vaal River Eastern Sub-System (VRESS) and is increasing much higher than inflation. Demand also initiates water transfers to provide 99.5% assurance to Generation (via Operating Rules), which thus requires water from expensive schemes. Should the water come from the Vaal, then the Vaal River Tariff becomes applicable.

6.3.2 Water cost and volume assumptions

The assumptions regarding annual increases in tariffs are based on the Water Pricing Strategy and historical information affecting tariffs. The plan is based on the following assumptions:

- Normal rainfall. Does not include drought mitigation plans.
- Return on Assets, Water Research Levy, Capital Unit Charge, third party and other tariffs increase at CPI of 6%

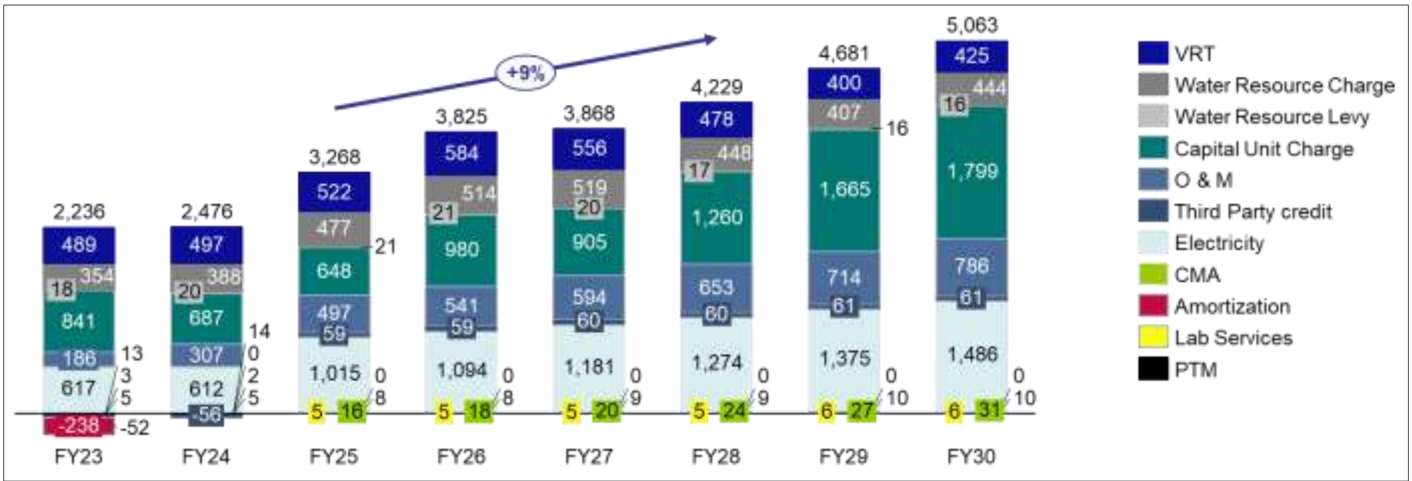
- The Vaal River Tariff increases at 9%
- O&M increases at CPI plus 4%
- The Catchment Management Agency tariff increases at CPI plus 7%
- Pumping costs increase at CPI plus 8%
- Tariffs for Medupi and Matimba comprise of MCWAP1 (included in the CUC) until FY2027. Thereafter, a tariff for MCWAP2 also applies.

6.3.2.1 Raw Water Usage & Cost

The power station performance targets are based on a regression model and a water balance model of each power station. This is then used to ascertain the quantum of water each power station will use in each period of the anticipated plans. The 50th percentile line of the power station performance is used as the basis for determining the amount of water that would be used by the power station. Any anticipated change at the power station that may impact on water use is accounted for as well. This is aggregated on a scheme-by-scheme basis and submitted to DWS bi-annually in April and October of each year. In forecasting the water use at each power station, cognisance is taken of the water quality and the points where the water will be sourced, based on the most recent dam operating rules that are available from DWS.

The figure below illustrates Generation's forecast water costs and a breakdown of the elements of water costs for coal stations respectively, for the period under review.

FIGURE 28: TOTAL COAL STATION RAW WATER COSTS (EXISTING AND NEW INFRASTRUCTURE)



Total water costs increase by an annual average of 9% over the FY2025 – FY2028 period.

- *The Vaal River Tariff (VRT), Water Research Levy and Water Resource Charge* are legislated tariffs. The tariffs are determined by the DWS. These costs are incurred per million litres (Ml) consumed.

- The Water Research Commission Levy (WRCL) is a tariff applicable to all water users in the country. The only distinction is between irrigation and other uses. At present, the tariff is charged on the actual consumption of the user. DWS may, in future, charge the tariff on registered use instead of actual use because of fluctuations in consumption. The money generated from this charge is paid over to the Water Research Commission by DWS.

- Water Resource Management Charge is a tariff set for a specific catchment area. The tariff applies to all the users and is applied on the registered use of a user and not on the actual volume used. The money generated from this charge is paid over to the Catchment Management Agency. The country is divided into 19 catchment areas.

- The Vaal River tariff (VRT) is a tariff applicable to all water users in the Vaal Catchment. At present, the tariff is charged on the actual consumption of the user. A portion of the money generated, approximately 83%, from this charge is paid over to the Trans Caledon Tunnel Authority (TCTA) by DWS. The DWS infrastructure associated with the scheme includes the following dams and their transfer infrastructure, the Thukela Scheme, Sterkfontein Dam, Heyshope Dam, Zaaihoek Dam, Grootdraai Dam, Vaal Dam and the Lesotho Highlands Transfer Scheme.

- *Capital Unit Charges (CUC):* The Water Pricing Strategy requires Generation to pay a capital unit charge (CUC) on assets owned by the DWS, which consists of a depreciation charge and an ROA charge. A depreciation charge is calculated based on the current replacement cost of the water infrastructure. The current ROA levy is 4% of the asset value. The pricing strategy makes provision for the revaluation of the assets and the original aim was to execute such a revaluation at 5-year intervals. The CUC is also a legislated tariff. The step change in FY2028 in the CUC is because of the introduction of the MCWAP2 tariff. The intent of the MCWAP2 is to increase the water supply to Medupi for the flue gas desulphurisation process and create a redundant water supply for both Medupi and Matimba power stations to ensure a 99.5% assurance of water supply. The DWS will also supply water to Lephalale Municipality and other mines in the area.

- *Operating and maintenance cost (O&M):* These costs vary depending on the specific contract Generation has with the supplier. Generation owns the Komati Scheme and has a 10-year contract with Eskom Rotek Industries (ERI), a subsidiary of Eskom, to perform the maintenance. Generation pays the actual operations and maintenance on the Usutu, Usutu-Vaal, Mokolo and Slang Schemes. The costs range from salaries, fuel and vehicle hire to the maintenance of the offices and accommodation for the staff. Current infrastructure is old. The DWA has a backlog of maintenance, which will contribute to the increase in the water tariff.

- *Electricity:* The cost that DWS incurs is a "pass through" to Generation. The electricity cost is affected by the forecast electricity consumption. The electricity demand is based on the pumping requirements to support the power station water demands and water transfers from various catchments to prevent dams from failing (*i.e.,* to prevent dam levels from falling so low that water cannot be released to power stations). DWS runs models to balance the inter-basin transfer of water. Due to the limitations of the transfer infrastructure and the uncertainty of climate conditions the lead time required to transfer water is very long. The base date for the DWS model is 01 May and the dam levels on that date are used in determining the operating rule. Transfer volumes increase in "dry or drought' years.

6.3.2.2 Water Risks

(i) Water Quality

The deteriorating water quality poses a major risk to Generation. The power stations will have to construct appropriate treatment plants and use chemical technologies to manage deteriorating water quality. The problem is further compounded by the management of the hazardous waste generated by the intake of "poor quality" water.

(ii) Implementation of the new Water Pricing Strategy

Water costs are regulated in line with the prevailing National Water Pricing Strategy. A new draft Water Pricing Strategy has been issued, but not finalised. Water tariffs could change once the draft Pricing Strategy is finalised. Water cost increases are primarily driven by increasing water demands of the new build, which require new water infrastructure and therefore higher capital tariffs to repay the financing debt.

The DWS's pricing strategy focuses mainly on water use in terms of volumes abstracted or stored and not on the discharge or disposal of waste or water containing waste or the associated effects. The waste discharge charge system, which will form a vital component of the pricing strategy, will address the latter by introducing financial and economic instruments, designed to internalise costs associated with waste, to encourage the reduction in waste and to minimise the detrimental effects on water resources. The DWS has not determined a mechanism and tariff for this charge. Eskom has not provided for this cost.

(iii) Drought or Infrastructure failure risk

The budget allows for the normal inter-basin water transfer required by DWS in its hydrological model. The model is fairly robust in forecasting one year. However, beyond a year, water transfer in drought conditions cannot be fully determined. No allowance/provisions have been made for either additional water transfers or water infrastructure that may be needed to mitigate the effects of drought. During drought conditions the water resource quality deteriorates which further exacerbates the water management problem at the power stations.

(iv) Water Supply Infrastructure failure risk

Power stations are planned to receive water from better quality sources, however during infrastructure failures some power stations will be expected to move to alternate water sources. These sources will attract additional tariffs and is also of poorer quality. Kriel, Kendal, Kusile and Duvha as such power stations.

6.4 Sorbent usage costs

Sorbent is required for the flue gas desulphurisation (FGD) technology at Medupi and Kusile Power Stations. The sources identified for this commodity are located in the Northern Cape. The Sorbent is railed from the Northern Cape to Gauteng. Then, because of a lack of rail infrastructure, it is trucked to the power stations. This process increases the delivered cost of Sorbent significantly.

The use of Sorbent also increases the water requirements at each of the above-mentioned power stations. The primary energy water volumes and cost include water for FGD at Kusile, based on a requirement of 0.45 litres per unit of energy sent out.

For this submission, the following assumptions have been made with regards to Sorbent:

6.4.1 Quantities required

The Sorbent volume requirements per station for each year are based on the GWh energy sent out per station. Medupi power station will be retro fitted with FGD at a later stage, so this plan include sorbent only for Kusile.

TABLE 26: ENERGY SENT OUT FOR STATIONS WITH FGD

GWh	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Kusile	9 119	9 525	15 956	19 198	19 041	16 988	14 574	16 143
Total	**9 119**	**9 525**	**15 956**	**19 198**	**19 041**	**16 988**	**14 574**	**16 143**

The estimated purchases of Sorbent are shown in the table below.

TABLE 27: VOLUME OF SORBENT REQUIRED (CONSUMPTION)

(Kt)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Volumes (kt)	201	71	380	457	453	404	347	384

6.4.2 The Cost of Sorbent

6.4.2.1 Key drivers affecting the cost of Sorbent

- The coal-fired power stations where Flue Gas Desulphurisation is planned are geographically remote from viable Sorbent sources; hence logistics and the final delivered cost will contribute to the selection of the most cost-effective option.
- Estimated pricing escalations are assumed to be driven by PPI.
- Greenfield sources will require capital investment in rail infrastructure and as such will require a return.

6.4.2.1.1 Cost assumptions:

- The cost of Sorbent for Kusile is R182/ton FCA (free carrier) in FY2026. This is based on the existing contract.
- The cost of transport for Kusile is R822/ton in FY2026. This includes the cost of the rail and road elements.

6.4.2.1.2 Cost escalations:

The Sorbent price and the transport cost have been escalated by PPI as per Generation's parameters.

TABLE 28: FORECAST PURCHASES COST OF SORBENT (R'M NOMINAL)

R 'M	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Limestone	34	19	64	83	87	82	74	87
Transport	204	85	291	376	395	372	337	393
Total	**238**	**104**	**355**	**459**	**482**	**454**	**411**	**480**

The purchases costs above translate into consumption costs as follows:

TABLE 29: FORECAST CONSUMPTION COST OF SORBENT (R'M NOMINAL)

R'M	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Costs (R 'M)	186	366	361	455	477	449	406	474

The decision to implement flue gas desulphurisation plant at Medupi and Kusile Power Stations is in line with environmental requirements to reduce emissions globally. There is a cost to implementing these measures. The long distance over which the Sorbent needs to be transported adds to this cost. Eskom is investigating options to reduce this cost, such as alternative sources of Sorbent which may be closer to the power stations. The cost of transport has been reduced by railing the limestone from the Northern Cape to Mpumalanga instead of Gauteng to reduce the distance on road. At this stage, the source with the capacity to supply the volumes required is the mine in the Northern Cape. Therefore, the costs have been based on this information.

6.4.3 Sorbent handling costs

Sorbent is required at Kusile for the flu gas desulphurisation (FGD). These costs relate to the handling of sorbent.

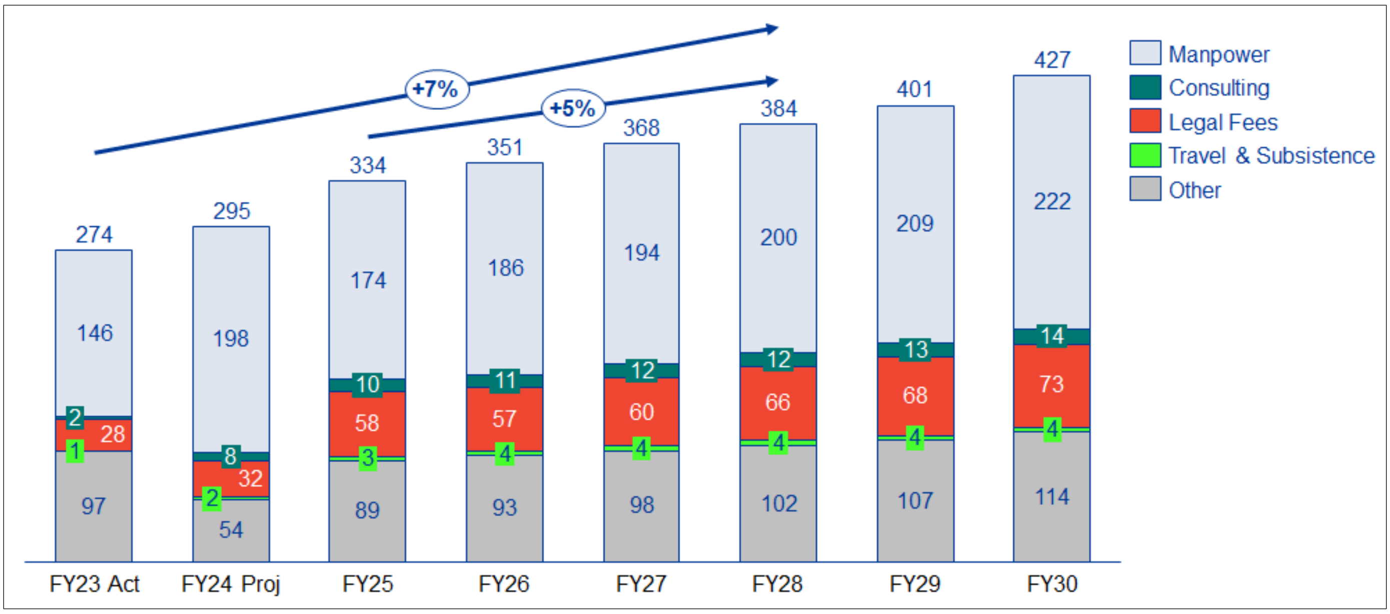
TABLE 30: SORBENT HANDLING COSTS

Sorbent Handling Costs (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Kusile	6	17	23	23	24	20	20	20
Total	**6**	**17**	**23**	**23**	**24**	**20**	**20**	**20**

6.5 Fuel Procurement Costs

These costs are incurred to operate the Primary Energy function. Apart from the provision for decommissioning and rehabilitating mines, the rest of these costs consist of manpower related costs. Manpower includes sourcing, technical, environmental, and operational staff, essential for managing the procurement and supply of coal from source to destination. These costs are not included in Generation's operating expenditure but are shown separately as Fuel Procurement Costs.

FIGURE 29: FUEL & WATER PROCUREMENT DEPARTMENTAL COSTS



Total costs increase by 7% from FY2023 and 5% over the FY2025 – FY2028 period. The largest cost component is manpower costs, which have been underspent in the past because of Eskom's moratorium on recruitment, salary increases for middle and senior management and bonuses. Hiring of new staff restarted in FY2024. PED intends to fill vacancies in the Technical Services and Coal Operations departments in FY2025. Manpower increases at the same rate as total Fuel Procurement costs.

Other costs include operating and administration costs, the largest of which are insurance premiums and international subscriptions to databases.

Legal fees increase substantially as Generation expects to need this service for, primarily, coal related matters.

6.6 Coal & Water Future Fuel

This section deals solely with the capital expenditure related to the acquisition of suitable coal and water in a safe manner. The motivations for this expenditure and any associated operating expenditure are included in the section below, which details per power station. Future fuel capital expenditure (capex) has a direct cash implication in the year that it is incurred. However, the effect on the bottom line is through the amortisation of the capex over the determined period. Some Capex is non-negotiable, e.g., Capex related to safety and environmental matters. Other Capex may be to replace equipment or to optimise production.

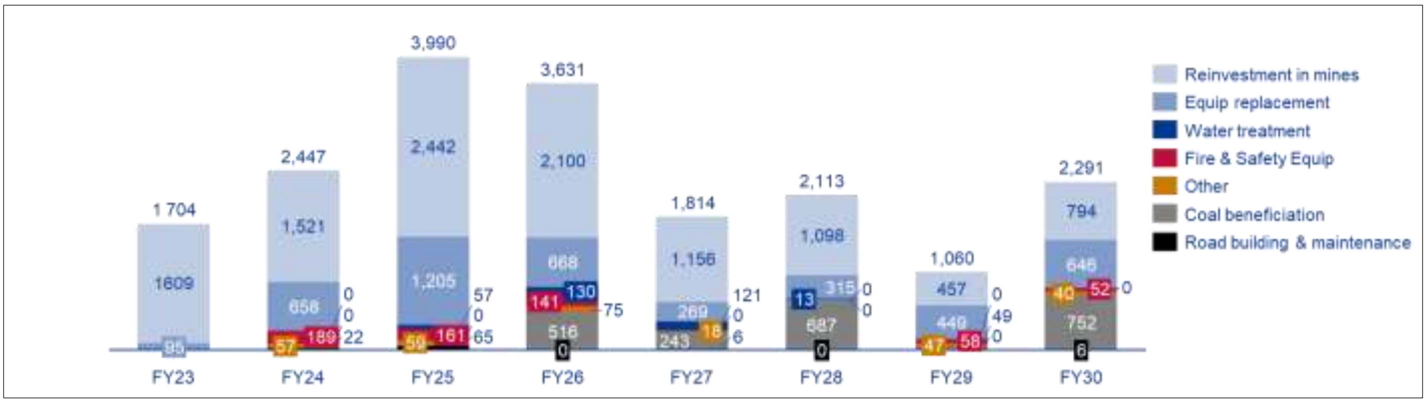
Future Fuel at Generation comprises investment in water related projects on the Komati Water Scheme and in coal projects at the cost plus mines. Expenditure on assets/projects which will yield benefits over more than one year is classified as future fuel and amortised over the life of that asset or project.

While the cost plus contracts allow the mines to spend capital, which Eskom has a contractual obligation to pay for this, the mines and Eskom work together to ensure that both the mining houses' and Eskom's governance processes are followed for all capex before the mines incur the expenditure.

Future Fuel expenditure is broken down into the following components:

- Reinvestment in mines: This is expenditure to open new areas for mining, extend the life of the mine or replace significant assets, e.g., a short wall.
- Equipment replacement: This is expenditure to replace equipment at the mines. Mines try to comply with OEM guidelines.
- Water treatment: This expenditure is often statutory and could result in Eskom paying fines or mine production stopping until legislation is complied with. Water may not be discharged into rivers and dams unless it meets quality standards that are mandated by the DWS. Water used by the power stations also needs to be of a certain quality. It needs to be treated because raw water does not meet these standards.
- Coal beneficiation
- Road building & maintenance
- Fire and Safety Equipment: This expenditure is often statutory and could result in Eskom paying fines or mine production stopping until legislation is complied with.
- Other: This is expenditure that does not fall into the preceding categories. It is typically relatively small. From FY2025 to FY2030, future fuel of R14.9 bn is forecast to be spent, R7.6 bn of which is forecast over FY2026 – FY2028. The largest expenditure of future fuel is reinvestment in the cost plus mines.

FIGURE 30: COAL AND WATER FUTURE FUEL SPEND (R'M)



Capital expenditure in FY2026 – FY2028:

Of the total expenditure in FY2026 – FY2028, 58% is reinvestment in the cost plus mines, 17% is to replace equipment at the mines, and 19% is to improve coal quality. The balance is water management and safety related. Further detail is provided below.

Reinvestment: The largest expenditure in this category is at Kriel Colliery for the development of Pits 11 and 13, which are required to start producing by FY2029 when the opencast production from Pit 4 will have been depleted. Expenditure at Matla Colliery is for the completion of the Mine 1 shaft. This project was delayed at inception at the DPE, which resulted in the completion being later and the cost being higher. Khutala Colliery is evaluating options to extend the underground mining into new areas, such as KLX Pits 1 to 4, and has included capex to execute Pit 1. These options are required to maintain production levels from FY2027. KLX Pit 1 is required to maintain production volumes from FY2027. New Denmark Colliery (NDC) is continuing with the development of the North Shaft, as well as replacing the longwall with CMs, which are more suitable for mining at NDC.

Equipment Replacement: New Vaal (Lethabo) is forecasting to spend the most on equipment replacement, and the largest part of this is the replacement of haul trucks, followed by hydraulic shovels, track dozers and graders. Khutala is replacing load haul dumpers and tractors. Kriel is spending most of the requested capex on the replacement of track dozers, a feeder breaker and shuttle cars. Matla is replacing a transformer and battery packs on the shuttle cars.

Water Treatment: Water treatment plants need to be constructed at Kilbarchan mine (old workings) and New Denmark to manage mine water being discharged. Matla has included capital for a brine pond.

Other: Eskom owns and is responsible for maintaining the Komati Water Scheme (KWS). In this submission, capital has been included to upgrade the switchgear, water flow meters and the SCADA (a system to monitor the plant operating on the KWS). Capital is included for a coal laboratory at Matla, as well as a training simulator to improve equipment handling and production. Matla Colliery is also required by the MDRE to improve their surface water management, so have provided funding for this. New Denmark has included capital for the construction of a dam to contain the water discharged from the underground workings, and for the sealing of an old shaft at the mine.

Coal Beneficiation: Kriel and New Denmark have provided for coal beneficiation plant to meet the power stations' required coal specifications. Managing coal quality to reduce load losses remains a key objective for Eskom.

6.7 Nuclear Fuel

6.7.1 Nuclear Fuel procurement (Fuel purchases of Nuclear future fuel)

Nuclear fuel procurement mainly comprise four categories, being Uranium, Uranium Conversion, Uranium Enrichment and Fuel Assembly manufacturing. The cost contribution per category depends on market prices and the ruling exchange rates. As per the latest available Term-market prices, the respective apportionment of the total cost is:

49% Raw Uranium

5% Uranium Conversion

23% Uranium Enrichment

23% Fuel Assembly manufacturing

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 table below shows the expenditure on acquiring the Nuclear Future Fuel which is held in Inventory until such time as it is placed into the reactor and burnt.

TABLE 31: TRANSFER OF COMPLETED FUEL ASSEMBLIES FROM NUCLEAR FUEL ASSET TO INVENTORY (NOMINAL R'M)

Transfer of completed fuel assemblies from nuclear fuel asset to inventory	Actual	Projection		Application			Post Application	
	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Transfer to nuclear fuel inventory from future fuel asset (R'm)	743	997	2 435	1 412	1 458	1 688	3 294	1 690
Delivery of Fuel Assemblies (Number)	60	60	112	60	60	60	120	60
Average Fuel Assembly Price (R'm)	12.39	16.62	21.68	23.53	24.30	28.13	27.45	28.17

The above nuclear fuel assembly prices are the average prices of the fuel assemblies delivered to Koeberg during that financial year. As noted in the projected numbers above, the nuclear fuel prices show an increasing trend, which has been evident for the last few years due to geo-political events as well as the drive to low-carbon energy solutions.

Generation has contracts in place that covers 100% of Koeberg’s demand until 2026 for fuel assembly fabrication, a contract for the procurement of uranium until 2028, a contract for conversion and enrichment services for 80% of Koeberg demand until 2028 and enriched uranium panel contracts for 20% of Koeberg demand until 2028.

The pricing formula for the fuel fabrication is 100% a base escalated price. For the rest, being the uranium, uranium conversion and uranium enrichment, a mix of price conditions have been agreed to being a mix between base escalated and market related prices, a mix between term and spot market prices and/or a reset of the base price to market during the contract period.

These prices are stated in the international functional currency of USD and are translated into rands at the rates provided by Eskom Treasury.

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

Fuel Procurement volumes will fluctuate as they follow the delivery requirements for Koeberg’s Production Plan. Fuel is required to be delivered approximately six months prior to each refuelling outage.

The fuel manufacturing process is approximately eighteen months with contractual progress payments throughout the fuel manufacturing cycle. As indicated above, this results in the above purchasing cashflows being different from the fuel burn expenditure in Primary Energy in the Income Statement.

6.7.2 Nuclear Primary energy Costs

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

TABLE 32: KOEBERG PRIMARY ENERGY COSTS (NOMINAL R'M)

Nuclear fuel burn R'm	Actual	Projection		Application			Post Application	
	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Nuclear fuel burn (Units 1+2)	513	497	632	848	1 396	1 496	1 758	1 906
Fuel written off	17	19	77	34	30	71	98	237
Depreciation of decomm asset	109	120	117	86	60	67	80	72
Nuclear Other	36	14	14	14	33	14	15	16
Total nuclear fuel burn costs	**675**	**649**	**840**	**982**	**1 519**	**1 648**	**1 951**	**2 231**

The costs above represent the following:

6.7.2.1 Unit 1 and Unit 2 "Fuel burnt"

These costs represent the fuel burnt as per the Production Plan.

Koeberg Power Station consists of two reactors each requiring loading of the reactor core of 157 fuel assemblies to achieve an even energy output as one third of the fuel assemblies are replaced at each refuelling cycle. The fuel assemblies loaded are expected to be burnt over a period of three cycles which equates to approximately 54 months. These fuel assemblies remain in the reactor core and are typically "burnt" over a period of approximately 54 months depending on the Production Plan and the refuelling strategies. The costs of the fresh fuel assemblies are amortised over the anticipated burn period and are reflected in primary energy costs.

However, based on the energy requirements some fuel assemblies may be changed and replaced with fresh fuel after only two cycles. This partially burnt assemblies are then expensed fully and removed from the reactor.

6.7.2.2 Depreciation of Decommissioned Asset: Spent Fuel Backend Costs

All the costs required to manage the spent fuel must be allocated to a period of production from which the benefit of burning the fuel is derived. Hence the costs relating to the long-term storage and disposal of the fuel is expensed over the period for which the fuel is burnt. This represents the variable costs of burning the fuel as should the fuel not be irradiated the costs would be avoided. The above charge to the income statement is credited to spent fuel provision thereby ensuring that the obligation for managing the spent fuel is correctly reflected on the balance sheet.

The spent fuel assemblies are stored in the spent fuel pools at Koeberg power station, however, given that Koeberg has been operating for over 39 years, the pools are reaching their capacity. The station has commenced acquiring spent fuel casks which will allow the spent fuel to be removed from the pools and stored in dual-purpose, storage and transport casks. With each fresh reload of fuel into the reactor core the displaced spent fuel from the core will require older and cooler spent fuel to be removed from the pool. Hence the cashflow expenditure relating to the spent fuel provision is being incurred now and will continue through to the end of life of the station. Unlike the plant decommissioning expenditure which is mainly incurred at the end of life of the station, the spent fuel decommissioning expenditure is a current and an ongoing cost.

6.7.2.3 Nuclear Other and Nuclear Fuel Write-offs

These costs represent the write-off of partially burnt fuel. Partially burnt fuel arises due to the required energy levels that must be maintained in the reactor as not all fuel assemblies can be fully burnt over the 54 months. The energy requirements from the fuel are calculated so as to ensure sufficient energy for the full duration of each cycle.

6.7.3 Link of the above activities to the Balance sheet

TABLE 33: NUCLEAR FUEL INVENTORY

Nuclear fuel Inventory R'm	Actual	Projection		Application			Post Application	
	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Opening balance	**1 920**	**2 113**	**2 571**	**4 289**	**4 795**	**4 832**	**4 954**	**6 381**
Add:								
Transfer to nuclear fuel inventory from future fuel asset	743	997	2 435	1 412	1 458	1 688	3 294	1 690
Less:								
Nuclear fuel burnt	(512)	(497)	(632)	(848)	(1 396)	(1 496)	(1 758)	(1 906)
Nuclear fuel written off	(17)	(19)	(77)	(34)	(30)	(71)	(98)	(237)
Nuclear spent fuel management:								
Increase in decommissioning asset	88	97	109	62	65	68	70	67
Depreciation of decomm asset	(109)	(120)	(117)	(86)	(60)	(67)	(80)	(72)
Closing balance	**2 113**	**2 571**	**4 289**	**4 795**	**4 832**	**4 954**	**6 381**	**5 923**

TABLE 34: NUCLEAR FUTURE FUEL ASSET

Nuclear Future Fuel Asset R'm	Actual	Projection		Application			Post Application	
	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Opening balance	**570**	**1 007**	**1 073**	**30**	**30**	**35**	**40**	**29**
Add:								
Nuclear future fuel capex *	1 179	1 064	1 392	1 412	1 463	1 693	3 283	1 696
Less:								
Transfer to nuclear fuel inventory from future fuel asset	(743)	(997)	(2 435)	(1 412)	(1 458)	(1 688)	(3 294)	(1 690)
Closing balance	**1 007**	**1 073**	**30**	**30**	**35**	**40**	**29**	**35**

6.8 OCGT fuel burn

6.8.1 Introduction to OCGT fuel

The purpose of this section is to provide information on how OCGTs are utilised to indicate their prudent usage considering the dynamics of the system. The focus is on the operational aspects of their usage. From a planning perspective, the OCGTs are considered together with the other available supply and demand options as peaking stations for use during peak hours which provides space for essential maintenance at baseload stations as well as for emergencies as a last resort before load reductions during extreme events.

The load factor for Eskom's OCGTs during the forecasting period was assumed to be 6% which translates to 1266 GWh per annum. This is based on the assumptions made when developing the production plan. Should the reality turn out to be different from the assumptions, then the OCGT usage could be higher than that assumed. The only possible mitigations against OCGT usage higher than the assumptions are increased dispatchable capacity (from either Eskom Generation or other generators) and improving the reliability and predictability of the Generation fleet.

The fuel used is mainly diesel (Ankerlig and Gourikwa). The price of the diesel is subject to the international USD price of Brent crude oil and the ZAR/USD exchange rate.

6.8.2 OCGT Specifications

Ankerlig and Gourikwa are heavy duty industrial gas turbines (Siemens) and can be used over a wide variety of loading regimes from peaking to baseload. Acacia and Port Rex are based on jet engine technology. Ankerlig and Gourikwa were constructed to assist with the demand supply balance predicted from the early 2000s because of their shorter (2-3 years) construction times. Originally, the business case for the OCGTs was based on a load factor of 6%.

6.8.3 OCGT utilisation plan

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

When the system is constrained, OCGTs are used to meet the remaining load when all other available generation is online. In winter this is typically for a few hours over evening peak due to the peaky load profile. However, in summer this may be for many hours per day due to the significantly flatter load profile. During the day, fewer units will be required than over the evening peak. OCGTs typically take about 20-30 minutes to come online and cannot all be brought on simultaneously. The number of units expected to be required for evening peak are brought on load prior to the sharp evening pick-up to ensure they are on load on time and prevent running at low frequencies. If the load does not materialise as expected there may appear to be extra machines on load but it is necessary that the machines are ready to support the load and the expected “peak in the peak”.

If large amounts of generation are lost, it is essential to have this quick response available to the System Operator. Hence the utilisation of OCGTs is done to meet total system demand; and may also be used to manage power transfer to the Cape. This may become an issue during Koeberg single or zero unit operation, as well as during certain transmission outages.

TABLE 35: OCGT ASSUMPTIONS

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

6.8.4 OCGT fuel costs

The price of the mix of gas fired stations was at the ruling rate of 1 November 2023. The price was then escalated with inflation parameters as indicated in the table below. There are monthly storage fees included for the fuel tanks where diesel stocks are kept off site.

TABLE 36: STORAGE AND DEMURRAGE FEES

Storage & demurrage fees (Rm)	Actuals	Projection		Application			Post Application	
	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Demurrage fees	1	14	14	15	16	17	17	18
Gourikwa storage	32	33	33	34	36	37	39	41
Ankerlig Storage fees	71	70	70	73	76	80	83	87
Total	**104**	**117**	**117**	**122**	**128**	**134**	**140**	**146**

TABLE 37: STATION FUEL PRICES CALCULATIONS

Fuel Prices (R/litre)	Actuals	Projection		Application			Post Application	
	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Acacia ruling price	0.00	12.35	12.70	13.34	13.98	14.60	14.60	15.26
Assumed fuel inflation			5.0%	4.8%	4.5%	4.5%	4.5%	4.5%
Forecasted price Jet A1			13.34	13.98	14.60	15.26	15.26	15.95
Port Rex ruling price	28.09	17.04	16.40	17.22	18.04	18.86	18.86	19.70
Assumed fuel inflation			5.0%	4.8%	4.5%	4.5%	4.5%	4.5%
Forecasted price kerosene			17.22	18.04	18.86	19.70	19.70	20.59
Ankerlig ruling price	21.78	21.01	23.68	24.87	26.06	27.23	28.46	29.74
Assumed fuel inflation			5.0%	4.8%	4.5%	4.5%	4.5%	4.5%
Forecasted price diesel			24.87	26.06	27.23	28.46	29.74	31.08

Fuel Prices (R/litre)	Actuals	Projection		Application			Post Application	
	FY2023	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Gourikwa ruling Price	22.19	20.03	23.68	24.87	26.06	27.23	28.46	29.74
Assumed fuel inflation			5.0%	4.8%	4.5%	4.5%	4.5%	4.5%
Forecasted price diesel			24.87	26.06	27.23	28.46	29.74	31.08

6.9 Coal handling

Coal handling refers to all the activities that are necessary to get the coal to the boiler once it has been delivered to the power station storage facilities and coal stockyards via a dedicated mine, road and / or rail. The main cost components of coal handling include labour, machinery and vehicles (such as Articulated Dump Trucks, tipper trucks, bobcats, bulldozers, which are known as white and yellow plant) and maintenance (e.g. conveyor maintenance, travelling chutes, tripper cars). 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 (e.g. number of conveyors, whether the conveyor systems are automated or manual) impacts on the employee number requirements at each station.

b) Yellow and white plant description and function:

Table 38: 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 description**
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. Articulated Dump Trucks (ADT's) 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.

6.9.1 The Drivers of Coal Handling costs

Coal handling is mainly driven by fixed costs which do not vary with production and / or the level of coal handling activity i.e., fixed costs in this context refers to labour and machinery anticipated at the time of contracting assuming the station is running at maximum continuous rating (MCR). Coal handling costs although mainly fixed, may vary (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 (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.

6.9.1.1 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 in different coal handling costs. 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, 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 boiler. For Kusile stockyard startup conditions, the normal operation is to stack coal on the stockyard and reclaim with mechanised equipment for the purpose of homogenisation to supply the boiler with consistent coal quality.
- When a mine supply conveyor breaks, additional handling via bulldozers and/or front-end loaders (yellow plant) would be required to manually feed coal into chutes or mobile feeders feeding onto conveyers into the boiler. The cost of conveyor repairs would also be allocated to coal handling.
- Although certain 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.

6.9.1.2 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.

6.9.1.3 Conveyor spills

If conveyers spill coal, labour is required to manually load the coal onto the conveyor using shovels.

6.9.1.4 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. Generally, the latter is more expensive from a coal handling perspective because of the use of mobile equipment.

6.9.1.5 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.

TABLE 39: COAL HANDLING COSTS (R'M)

Coal Handling (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Coal Handling (R'm)	2 293	2 419	3 090	3 314	3 469	3 633	3 801	3 988

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.

6.10 Water treatment

Raw water is used for various water production processes at the station, including for direct make-up to the cooling water system, potable water and many other uses at the station.

TABLE 40: WATER TREATMENT COSTS (R'M)

Water Treatment Costs (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Water Treatment Costs (R'm)	669	848	1 004	1 014	986	1 029	1 105	1 103

6.10.1 Description of Water Treatment Processes

There are six main water treatment processes:

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

6.10.1.1 Demineralised Water Production

- Demineralised water is produced at the power station as it is fed to the Generating Units for the production of steam that turns the turbines.

- Raw water is treated in a pretreatment plant (before it is introduced into the ion exchange vessels), which comprises clarifiers and filtration systems, to produce filtered water and potable water. Filtration is one of the processes that is used in the chain of processes required for the production of demineralised water. In the pretreatment process, various pretreatment chemicals are used, including coagulants, flocculants and disinfectants which are the main costs of this process.

- Filtered water is then further treated in the demineralised water production plant. At most stations, ion exchange processes are used for demineralised water production, whereas at a few stations, membrane processes are used to produce demineralised water. The power station design determines which process is employed at a particular power station. Filtered water is either routed to the ion exchange vessels for the production of deminerlised water or is routed to disinfection for the production of potable water.

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

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

Factors which contribute to increased chemical usage are as follows:

- Change in raw water quality: The design of the demineralised water production process is based on a specific raw water quality. A deterioration in the raw water quality compromises the efficiency of the demineralised water production process and results in more frequent regenerations, requiring additional cleaning measures having to be implemented at 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 due to several possible reasons (e.g. leaks, channelling of chemicals in the resin bed, manual chemical injection and control being effected). 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. The targets are determined via a process that considers the targets set during the design of the generating units and that considers the historical targets. The increase in demineralized water consumption is due to mechanical defects on the generating units and due to the high number of start-ups that are being conducted on the generating units (this in turn is related to the high number of trips across Generation and the high unit unavailability). 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.

- 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 will continue to be a risk. This increases the cost of demineralised water production and condensate polishing. The impact on the station's water treatment expenditure is dependent on how many imported caustic soda deliveries are required during the month, which in turn is 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.

6.10.1.2 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 townships, 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/quantity of consumption of potable water by the different users.

6.10.1.3 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.

- Some of the older stations were designed without a condensate polishing plant. This was based on many factors including the technology available at the time, the age and size of the station, and costs. Therefore, some stations do not have this plant installed. They apply different chemical treatment regimes, and different chemistry limits.

- Condensate polishing plants utilise ion exchange resin beads, loaded in vessels on the units, to remove impurities from the water on the units. When the resin beads are “exhausted” after a certain run length, the resin is transferred to a condensate polisher regeneration plant at the water treatment plant, for the resin to be regenerated. This resin is regenerated using the chemicals, sulphuric acid and caustic soda.

- The quantity of chemicals used for condensate polishing is mainly dependent on the frequency of ion exchange resin regenerations. The latter is influenced by the level of impurity ingress into the water/steam cycle, the condition of the ion exchange resins, and the efficiency of the regeneration process.

6.10.1.4 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 system. 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 41: TABLE INDICATING MAIN COOLING TECHNOLOGIES IMPLEMENTED IN ESKOM

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

- 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.

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

- Change in raw water quality: The design of the cooling water treatment process is based on a specific raw water quality. A deterioration in the raw water quality compromises the efficiency of the treatment process which increases the treatment cost. Some of the stations have experienced a deterioration in the quality of the raw water.

- Raw water make-up to the cooling water system: The higher the make-up, the more salts enter the cooling water circuit, and the higher the water treatment cost. The make-up is influenced by water losses in the cooling water circuit.

- Deterioration in the availability, reliability and efficiency of the cooling water treatment plant: A decrease in the availability and reliability of cooling water treatment plants results in less water treatment taking place and less costs being incurred. A decrease in efficiency results in more chemicals being used, increasing the cost of treatment. The refurbishment of the cooling water treatment plants has been identified as a focus area. This is being addressed through the implementation of maintenance strategies at the stations. The cost of cooling water is expected to increase back to normal as the availability, reliability and efficiency of the cooling water treatment plants is restored.

- Recovery of drains, ash water, mine water or wastewater to the cooling water system: Depending on the quality of these streams, the recovery can increase or decrease the cost of cooling water treatment.

- Cost of chemicals used for cooling water treatment: Some stations experienced an increased cost in cooling water treatment due to issues with the procurement of chemicals. To address this, national contracts have been established for bulk chemicals, such as lime, and stations are putting in place long-term contracts for the other chemicals.

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

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

6.10.1.5 Ash Water Treatment

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

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

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

- The cost of ash water treatment is driven by the cost of the chemicals used for the treatment.

6.10.1.6 Sewage Treatment

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

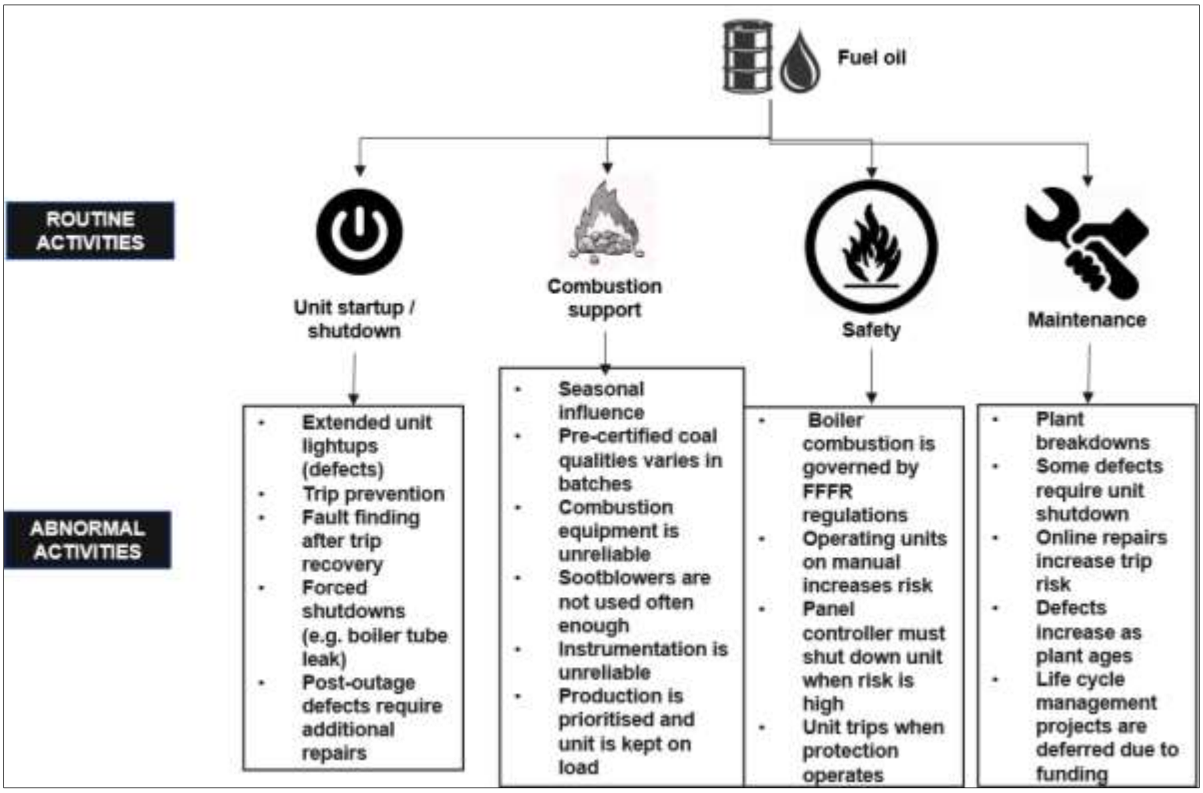
- At sites that have a township that accommodates Eskom employees and their families, a separate sewage treatment plant is installed to receive and treat the sewage from the township residents / facilities.

- Most power stations have contracts in place to outsource the operation and maintenance of these plants. The cost of sewage treatment is also driven by the cost of the chemicals used for the treatment.

6.11 Fuel Oil

6.11.1 Main drivers of Fuel-oil Usage

Figure 31: Routine fuel oil usage categories



6.11.1.1 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.

6.11.1.2 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

TABLE 42: GENERATION FUEL OIL COSTS (R'M)

Fuel Oil Costs (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Fuel Oil Costs (R'm)	8 807	8 932	9 845	10 745	11 086	11 485	11 964	11 975

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.

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.

Historically, 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 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.

6.12 Environmental levy

TABLE 43: ENVIRONMENTAL LEVY COSTS

Environmental Levy (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Environmental Levy	7 033	6 829	6 861	6 539	6 279	5 337	4 781	4 767
TOTAL GENERATION	**7033**	**6 829**	**6 861**	**6 539**	**6 279**	**5 337**	**4 781**	**4 767**

6.12.1 Introduction

The Customs and Excise Act, 1964 promulgated in July 2009 that the generation of electricity from non-Renewable generators is liable to pay an Environmental Levy. The Government Gazette No 32309 dated 01 July 2012 set the rate at 3.5 c/kWh on the generated volume. All Eskom power stations with the exclusion of Hydro and Pumped Storage were registered and licenced as manufacturing warehouses as required by legislation.

6.12.2 Process

According to the Act, the owner of the "Manufacturing Warehouse" is accountable for the compliance to the Act. In Generation's case it is the Power Station Manager of each power station. With twenty different sites liable for the payment of the Environmental Levy it is necessary to manage, consolidate and plan on a centralised basis to ensure full compliance from all participants. Each power station has procedures in place which govern this process. The Act requires the appointment of a Responsible Person. Power Station Managers are required to appoint a Production Manager and a Financial Manager in writing as responsible for full compliance to all aspects of the process.

6.12.3 Planning

The first principle of this application is that it must be fully aligned with the official approved Generation sales volumes. The Generation Production Plan is the only source that could be used as a prudent source of the volume applicable which is liable for the payment of the Environmental Levy. The Production Plan takes cognisance of all supply requirements such as imports and IPP supply and then on a least cost methodology allocate supply to generators to meet the sales demand.

Power station volumes as expressed in the Production Plan are measured at the bus bar of each power station where it is exported onto the Transmission grid. The common terminology used for energy at this point is "Energy Sent Out" (ESO).

Since the Act imposes the Environmental Levy on generated volumes as measured at the generator of the power station one needs to derive the difference between generated energy and sent out. This difference in volume is the energy consumed by the power station (also known as auxiliary consumption) which is not available to be exported onto the grid.

This auxiliary volume is expressed as a percentage of sent out energy known as the Aux % of a power station and ultimately added to the sent-out energy as expressed in the Production Plan. The result is the gross generated volume on which the Levy is calculated, and which is fully aligned with the overall sales plan.

The auxiliary consumption of the power station is for unit auxiliary equipment, common plant such as lighting and lifts, and outside plant such as conveyer systems, admin buildings, laboratories, stores, security, and water and ash plants.

The Aux % for each power station is different and fluctuates from hour to hour. Auxiliary equipment differs between generators. There is little direct short-term correlation between Aux % and energy sent out at a power station. The auxiliary consumption on common plant does not reduce linearly when the production from one or more of the units reduces or stops due to planned or unplanned events. This variability will therefore mostly result in variances between a power station's estimated auxiliary consumption and the actual volumes consumed.

The system Aux % should not be seen as a constant. Variances in individual power station Aux %, as well as variances in ratio of production between power stations and between renewable / non-renewable sources will result in Levy cost variances.

6.13 Carbon Tax

The carbon tax has been introduced by National Treasury, in addition to the existing environmental levy on the generation of electricity from non-renewable resources.

TABLE 44: CARBON TAX LIABILITY CALCULATION FOR GENERATION

Carbon dioxide emissions*	Projection		Application			Post Application	
	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Acacia	1	0	0	0	0	0	0
Ankerlig**	1 086	653	652	652	652	652	652
Gourikwa**	1 031	411	411	411	411	411	411
Port Rex	2	0	0	0	0	0	0
Kusile	8 336	12 997	19 198	19 041	16 988	14 574	16 143
Medupi	20 914	21 242	18 347	16 328	15 753	14 053	14 245
Duvha	14 023	9 801	10 106	9 181	6 890	5 838	3 376
Kendal	12 204	18 606	16 729	18 452	15 297	14 420	14 371
Lethabo	23 803	21 317	17 417	16 910	14 016	13 965	14 120
Majuba	22 064	17 644	16 652	18 411	12 305	11 319	10 861
Matimba	19 404	21 682	16 506	16 262	16 431	14 328	14 340
Matla	16 096	16 860	16 099	14 324	13 927	11 098	9 841
Tutuka	8 614	9 062	11 502	8 679	4 759	3 175	3 225
Arnot	11 869	9 528	10 610	9 218	8 127	6 482	6 093

Carbon dioxide emissions*	Projection		Application			Post Application	
	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029	FY2030
Camden	10 830	7 917	6 867	6 163	1 945	1 708	1 688
Grootvlei	2 916	3 720	2803	1 387	1 350	1 413	1 525
Hendrina	4 229	5 173	5 586	2 856	1 658	1 607	1 691
Komati	-	-	0	0	0	0	0
Kriel 1_3 (UG)	4 958	7 127	4 603	5 345	4 686	4 403	4 242
Kriel 4_6 (OC)	5 902	4 940	6 662	4 957	5 383	3 682	5 047
Kusile Pre-Comm	1 411	2958	-	-	-	0	0
Medupi Pre-Comm	-	-	0	0	0	0	0
Virtual Station (coal fired average 1.2 tonnes CO_2/MWh)	0	0	0	0	0	0	0
Total qualifying carbon dioxide (CO_2) emissions (kilotonnes) [a]	187 573	190 575	179 687	167 515	139 516	122 065	120 807
Multiply: tax-free allowances*** (60% for category 1A1a) [b] = [a] x 0.6	112 544	114 345	107 812	100 509	83 710	73 239	72 484
Net emission equivalent [c] = [a] - [b]	**75 029**	**76 230**	**71 875**	**67 006**	**55 806**	**48 826**	**48 323**
Carbon tax rate in R/tonneCO_2eq [d]*****	159	190	236	308	347	385	424
Carbon tax rate in R/tonneCO_2eq [e]*****	190	236	308	347	385	424	462
Gross carbon tax levy liability (Rm) [f] = [[0.75 x [c] x [d]] + [0.25 x [c] x [e]]]/1000	**12511**	**15360**	**18256**	**21291**	**19895**	**19274**	**20948**
Additional deductions to "generators of electricity from fossil-fuels" [g]	Environmental levy paid; Renewable premium calculated on REIPPPP volumes		0 from 1 January 2025 (last 3 months of the FY)	0			
Net carbon tax levy liability after deductions (Rm) [h] = [f] - [g]	**0**	**0**	**5 534**	**21 291**	**19 895**	**19 274**	**20 948**

* Station-specific emission factors (tonnes CO2/MWh sent out) were utilised (excluding additional greenhouse gases of nitrous oxide (N2O) and methane (CH4) which are reported to the Department of Environment, Forestry and Fisheries and which also incur the "carbon" tax. The addition of these gases adds roughly 0.5% to the gross CO2eq emissions. Comprehensive station-specific emission factors are being developed for future use.

** Ankerlig, and Gourikwa, Acacia and Port Rex utilise diesel. Greenhouse gas emissions for diesel are taxed at source (i.e. included in the fuel costs).

*** Currently category 1A1a emissions have a 60% basic tax-free threshold. Additional allowances for carbon budgets (5%) and trade (4.87%) may or may not be accessible to Generation in future years as the regulations for carbon budgets will only be gazetted after the Climate Change Bill is enacted.

***** Annual tax rate increases from R159/tonneCO2eq in 2023 up to R462/tonneCO2q in 2030 have been gazetted

***** The tax liability in a financial year will attract two different rates (emissions from 1 April to 31 December will be at one rate and emissions from 1 January to 31 March will be at another rate) hence when applying the calculations to the FY volumes, the two rates are applied to three quarters and then the remaining quarter (0.75 and 0.25).

6.13.1 Activities subject to the tax

The Carbon Tax Act, no 15 of 2019 came into effect from 1 June 2019. This Act provides for the imposition of a tax on the greenhouse gas emissions of a company (expressed in carbon dioxide equivalents (CO_2eq)) and matters connected therewith.

There is a popular misconception that Eskom is exempt from the tax which is not true. A taxpayer is liable "if that person conducts an activity in the Republic resulting in greenhouse gas emissions above the threshold determined by matching the activity listed in the column ''Activity/Sector'' in Schedule 2 of the act, with the number in the corresponding line of the column ''Threshold'' of that table. **Generation** currently conducts one activity listed in Schedule 2 where the corresponding threshold is exceeded, namely activity 1A1a (Main Activity Electricity and Heat Production). **Transmission and Distribution** also conduct activities, namely 1A3a (Domestic Aviation) and 2G1b (Use of Electrical Equipment) that are subject to the carbon tax and their carbon tax liabilities are reported elsewhere.

6.13.2 Emissions data

The tax base should be the sum of emissions over the preceding calendar year - determined either according to a reporting methodology approved by the Department of Forestry, Fisheries and Environment (DFFE) or determined in accordance with the formulas and input values provided for in the act. Since 2017, Generation already reports greenhouse gas emissions to DFFE using an approved “Tier 3” methodology, as required by the National Greenhouse Gas Reporting Regulations of 3 April 2017 (notice no 40762).

6.13.3 Tax rate

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

6.13.4 Allowances

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

The latest Budget Review states that National Treasury will be releasing a discussion document in the course of 2024 that provides details on their proposal to gradually reduce the basic tax-free allowances (currently 60% for category 1A1a) from 1 January 2026 to 31 December 2030. A reduction in the basic tax-free allowance would cause the projected liabilities to increase further.

According to the published trade-exposure regulations (GG no. 43451), under the Standard Industrial Classification (SIC) code of 411, the production, distribution and collection of electricity qualifies for only 4.87%.

According to the published performance allowance regulations (GG no. 43452), there is no performance benchmark provided for the electricity sector, the domestic aviation sector or the use of electrical equipment and therefore no allowance can be claimed.

The carbon budget allowance is expected to be phased out after the Climate Change bill is passed and associated regulations (for mandatory carbon budgets) are finalised.

Lastly, the offset allowance requires that an entity purchase offset credits up to a maximum of 10%. Generation does not expect to purchase offsets during the current phase of the carbon tax and **future purchases would only be undertaken if such expenditure was considered prudent and the cost of the purchases would also be passed through** (i.e. if the cost of the purchases was equal to or less than the amount of carbon tax avoided).

TABLE 45: TAX-FREE ALLOWANCE CATEGORIES

IPCC code/ Emissions category	Basic tax-free allowance for fossil fuel combustion emissions %	Basic tax-free allowance for process emissions %	Fugitive emissions allowance %	Trade exposure allowance %	Performance allowance %	Carbon budget allowance %	Offset allowance %	Maximum total allowances %
1A1a	*60 – can be claimed*	*0*	*0*	*10 – 4.87% can be claimed for now*	*5 – no benchmark published, cannot be claimed*	*5 - can be claimed currently but will no longer be available after carbon budgets become mandatory under the expected Climate Change Act*	*10 – requires an entity to purchase carbon offsets, up to a maximum of 10%*	*90 – however, only 60% (the basic allowance) can be assured at this time*
1A3a	*75 – can be claimed*	*0*	*0*	*0*	*5 – no benchmark published, cannot be claimed*	*5 – was not included in Eskom's pilot carbon budget and cannot be claimed*	*10 – requires an entity to purchase carbon offsets, up to a maximum of 10%*	*95 – however, only 75% (the basic allowance) can be assured at this time*
2G1b	*n/a*	*60 – calculation for process emissions to be checked for applicability*	*0*	*10 – gazette for trade exposure to be checked for applicability*	*5 – no benchmark published, cannot be claimed*	*5 – was not included in Eskom's pilot carbon budget and cannot be claimed*	*10 – requires an entity to purchase carbon offsets, up to a maximum of 10%*	*90 – however, applicability of various allowances to be confirmed given this is a new addition*

6.13.5 Additional deductions during Phase 1 (ends 31 December 2025)

The Carbon Tax Act allows Generation (as a "generator of electricity from fossil-fuels") to make two extra deductions from the carbon tax liability during "phase 1" of the carbon tax. These deductions are only allowed until 31 December 2025. The first deduction is equivalent to the renewable energy premium that has been paid in a tax period. This is calculated based on the renewable energy purchases in each category, multiplied by the gazetted premium. The second deduction is equivalent to the amount equal to the environmental levy that has been paid in a tax period. For the previous carbon tax declarations (October 2020, July 2021, July 2022 and July 2023), these two deductions have been sufficient to nullify the carbon tax liability. From 1 January 2026, when these deductions fall away, the full carbon tax liability is expected to be passed through.

6.13.6 Opportunities to reduce Generation's greenhouse gas emissions

Coal-fired power stations produce greenhouse gases as a by-product of the coal combustion process. Unlike the local air pollutants (Sulphur dioxide, nitrogen oxides and particulate matter), **there is currently no commercially viable technology to capture carbon (either to store or for re-use) from large coal-fired power stations**. Hence, electricity sector greenhouse gas emissions are closely tied to electricity production from coal (and to a lesser extent gas) fired power stations. As the single largest contributor to South Africa's greenhouse gas emissions, rapid decarbonisation of the electricity sector is required in order for the country to be able to meet the international commitments made under the Paris Agreement. The rate at which this decarbonisation can be achieved, depends largely on the outcomes of the Integrated Resource Planning processes of the Department of Mineral Resources and Energy. It should be noted that **even with the absolute reduction of greenhouse gas emissions, a carbon tax will still be payable** given that the tax-free allowances are percentage-based.

6.13.7 Carbon tax/Carbon budget alignment

The carbon tax is one instrument that has been implemented to try and encourage a reduction in greenhouse gas emissions by providing a pricing signal to consumers. The Department of Environment, Forestry and Fisheries have also piloted another instrument in the form of a carbon budget. A carbon budget essentially provides a greenhouse gas emissions allocation to an emitter. The Climate Change bill makes provision for the allocation rules for future carbon budgets to be laid out in regulations. National Treasury and the Department of Environment, Forestry and Fisheries have committed to align these two instruments with a view to reducing the burden of compliance on industry and ensuring the efficacy of the instruments to reduce emissions. It is possible that the carbon budget could be used in a two-tier process that triggers an even higher carbon tax for emissions which exceed the budget (a value of R640/tonne CO_2eq has been indicated by National Treasury).

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

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

7 Operating Costs (Opex)

7.1 Introduction to Operating Expenditure

Operating costs (Opex) comprises three categories, namely manpower costs, maintenance and other opex. Other Income and a pro-rata portion of corporate overheads are also included.

7.2 Summary of operating costs

TABLE 46: OVERALL SUMMARY OF OPERATING COSTS

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

7.3 Manpower

In the current business operations Generation's key goal in the short term is to turnaround performance and increase EAF in a financially, operationally and environmentally sustainable manner which requires critical interventions in;

- **Filling of vacancies**: The current number of vacancies and performance in Generation requires immediate, critical interventions to improve current performance which will in turn enable the future business direction.
  - Create leadership stability by filling all vacant positions.
  - Fastrack the filling of all vacant positions in the auxiliary plant including all other critical vacancies.
- **Skills and competencies**: Optimisation of current skill base and new skills are required in the short term.
  - Generation will close the skill gaps identified through the conducted skills audit.
  - Analyse and assess employee's skills and competency in the auxiliary plant, that is Maintenance, Engineering, Operating and Contracts Management in alignment with the Generation Recovery Plan.

- Review of Generation's learner pipeline to ensure sufficient through-flow of skills to support Operating, Maintenance and Engineering
- Continue with Generation Technical Leadership Programme and Management Development Programme for Snr Managers, Managers and Supervisors.
- Rolling out Executive Coaching and Mentorship geared for Power Station General Managers.

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

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

7.3.1 Generation Licensee Employee Numbers

Manpower costs are predominantly driven by employee numbers.

The employee numbers of Generation for the MYPD 6 period are as follows:

TABLE 47: GENERATION EMPLOYEE NUMBERS

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

7.3.1.1 Comparison with International Norms

Generation's own further research, based on published US Government data, indicates that the ratio of generation plant capacity per employee for US coal power stations is around 3.38MW per employee.

The Generation Coal Fleet averages around 4.4 MW/Head over the MYPD 6 period. This compares favourably to US coal power stations.

7.3.2 Employee Benefits Costs

The employee numbers result in the following Employee Benefits costs:

TABLE 48: TOTAL GENERATION EMPLOYEE BENEFIT COSTS

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

Employee benefit costs are mainly driven by:

- The ***number of employees*** – Permanent employees and full-time equivalents (FTE's)
- 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.

For FY2023 to FY2025 a 7% annual increase for bargaining unit level employees is applied as per the collective bargaining agreement. For subsequent years the salary increase is assumed for all employees to be CPI.

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 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) are 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) Thirteenth Cheque/Rewards

- **Thirteenth Cheque**

This is 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 (part of the cost of company) 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.

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 certain 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 (e.g. unemployment insurance) and others such as death benefit funds.

i) 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.

j) Training and Development: for attending external training at a university or other training institution (including training material). Examples include developing technical skills of the employees.

k) Temporary and contract staff costs:

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

l) Other staff costs

- **Professional institution fees**: Subscriptions paid to professional bodies on behalf of employees e.g. ECSA, SAICA, CIMA.
- **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.
- **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 costs**: The separation packages given to employees where those employees voluntarily leave Eskom's employ.

m) 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.

n) 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

7.4 Maintenance cost

TABLE 49: GENERATION MAINTENANCE OPEX

Maintenance Opex (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030

Gx Total Maintenance Opex	16 581	19 332	22 021	21 742	20 693	22 224	21 249	23 462

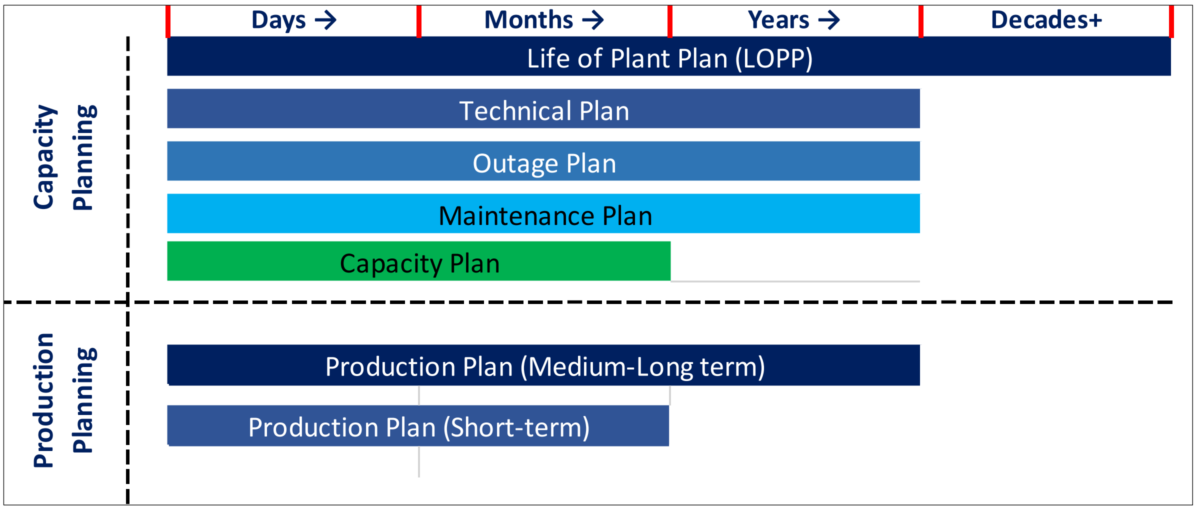
7.4.1 Introduction

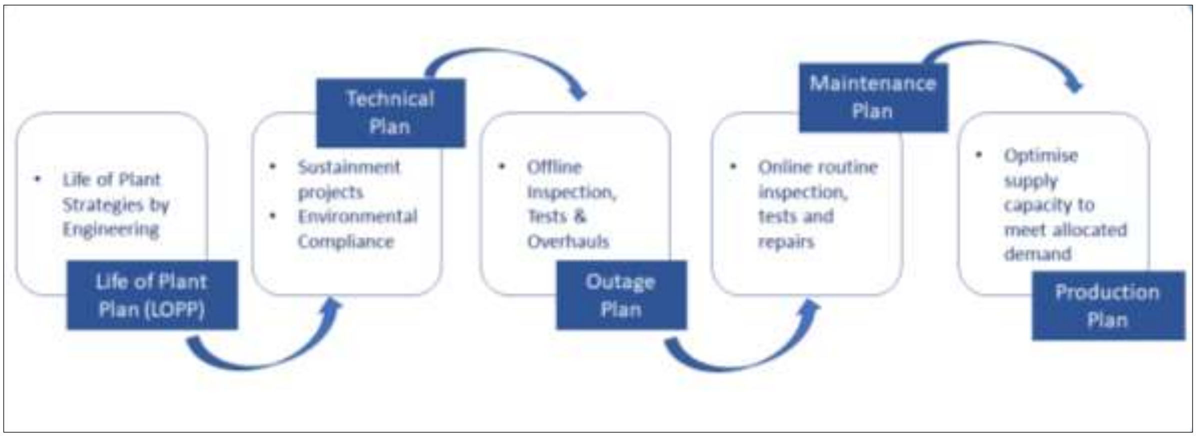
Generation adopts a variety of appropriate online and offline (outage) maintenance strategies ranging from preventive to predictive and proactive maintenance, in addition to corrective (or breakdown) maintenance. Adherence to the defined maintenance strategies will ensure that plant is operated in a manner that is safe, compliant to all regulatory and legislative requirements, and reliable. Maintenance strategies are defined for the short term and longer term to sustain the plant operational state and does not include significant life extension or modernisation of the generating plant assets.

These maintenance strategies are detailed for each item of plant and determines the maintenance work activities at varying intervals to inform the maintenance plans and consequently the expenditure (both operational and capital) required for the fleet of generating plant. Maintenance operational expenditure is derived from routine online and offline maintenance work (typically inspections and related repairs including breakdowns), while maintenance capitalised expenditure arises from major maintenance activities at extended intervals, especially during outages and for projects requiring major replacements or refurbishments.

The Life of Plant Plan (LOPP), details these major maintenance and refurbishment projects that are required over the life of the plant. The Technical Plan is a more refined extract of the LOPP over a shorter period and the Maintenance Plan is a listing of the outages required to implement the LOPP and Technical Plans. The online maintenance, offline maintenance and refurbishment/replacement plans inform the routine maintenance plans, the Outage Plans and the LOPP (up to end of station life) or Technical Plans (a five-year view of the LOPP). The Capacity Plan takes a detailed view of the first year of these plans to ensure that all required outages are scheduled whilst ensuring there is adequate capacity available to meet demand. Production Planning describes how the required energy demand is to be met on an hourly basis whilst maintaining least-cost dispatch within known constraints.

FIGURE 32: MAINTENANCE PLANNING OVERVIEW





The LOPP is a plan of major maintenance and refurbishment interventions that are required over the full life of the station. Generation uses a plant-aged assumption for long term planning including the Generation expansion, financial and LOPP, however, the actual life is not determined by age but the economic viability. This is determined by the need to make the mandatory or necessary investments at intervals at critical plant life milestones set by the design, operation and maintenance of the plant.

The Outage Plan is based on a codified preventive maintenance strategy for each power station. This prescribes what maintenance interventions are required at what periodicity as well as the standard maintenance activities required. Stations have specific requirements with respect to the numerous cyclical maintenance interventions required on a power plant. However, generic rules exist:

- General Overhaul (GO): typically every 10 – 12 years plant shutdown to do inspection and repair of turbine and generator.

- Mini-Overhaul: Every 5 - 6 years inspection of low-pressure turbines, and statutory pressure testing
- Interim Repair (IR): 18 – 36 month, plant is shutdown to inspect and repair the boiler and boiler auxiliary components.
- Boiler Inspection (IN): Between IR's an inspection is carried out to conduct inspections and condition assessments of the boiler and its auxiliaries to better scope and plan the next outage.

The outage interventions should be adhered to as far as possible and optimised depending on how the plant is operated between each outage intervention to ensure safe and reliable operation of the key plant components. Appropriate risk assessments are mandated where a deviation from the outage routine would be required to ensure that suitable mitigations are in place and to avoid deteriorated plant condition or reliability.

Outage interventions are prioritised if needed by scheduling outages according to the following priority:

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

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

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

It is important to note that this *does not* represent the Total Maintenance Cost i.e., it excludes the capitalised portion which is categorised as Outage Capex and Tech Plan Capex. All 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 (due to 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. 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.

7.4.1.2 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 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 started 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 MYPD 3 revenue cycle, namely insufficient funds to perform the required maintenance due to the sub-cost-reflective revenues.

7.4.2 Maintenance Cost Benchmarking

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 33: INTERNATIONAL APPROACH OF MEASURING THE EFFICIENCY OF A UTILITY'S MAINTENANCE SPEND

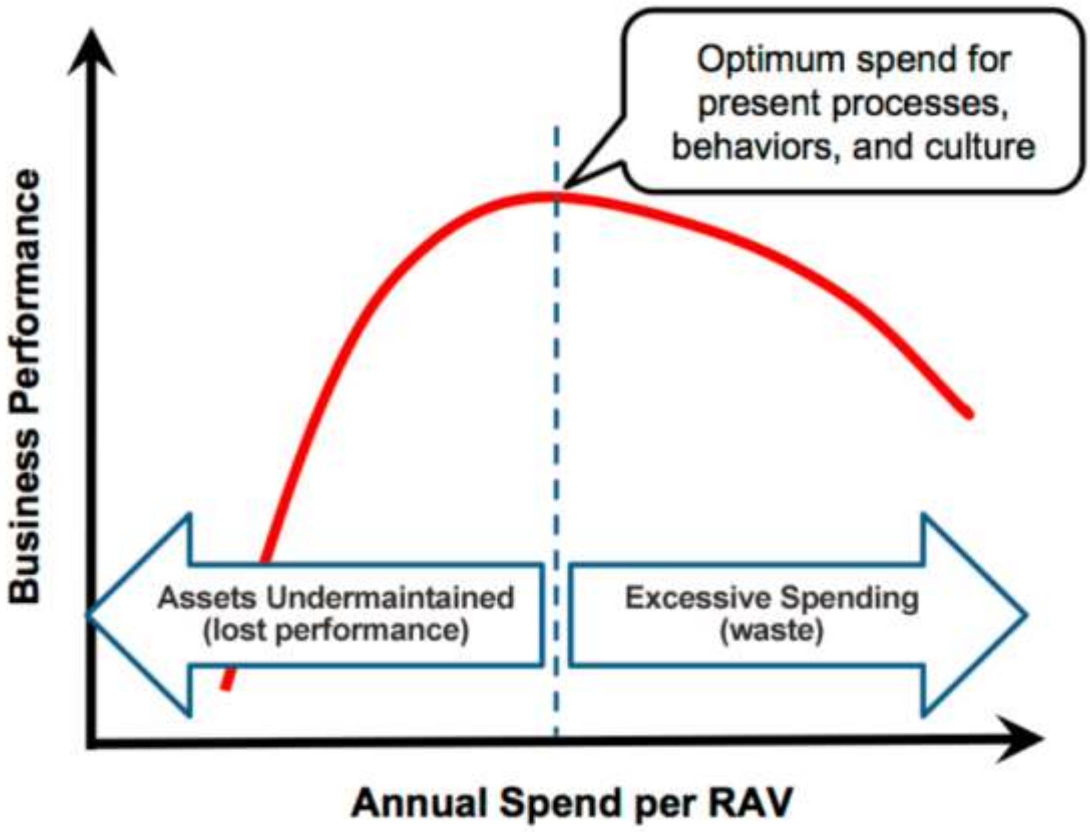
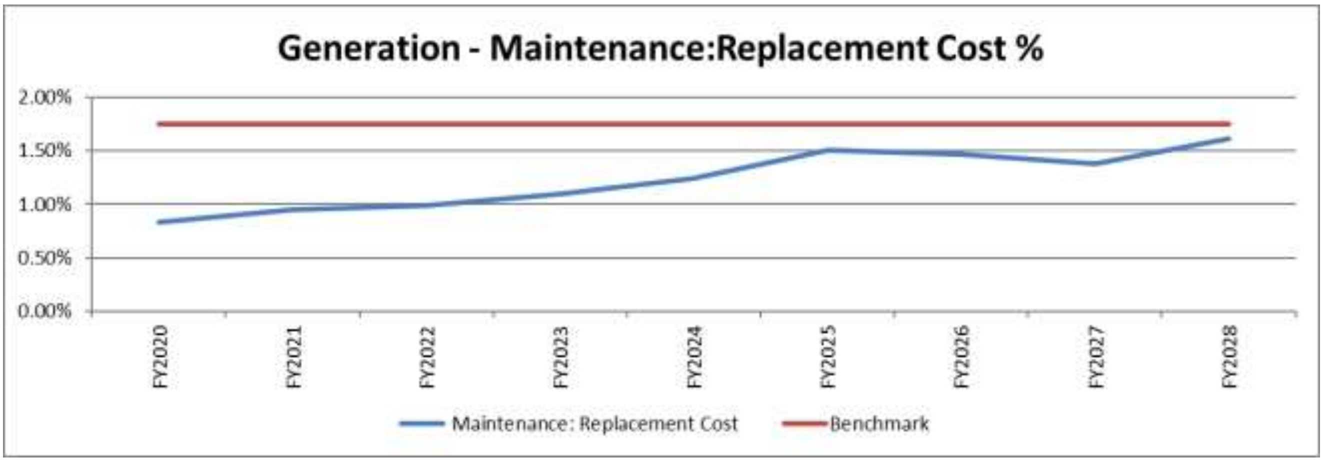


FIGURE 34: GENERATION MAINTENANCE REPLACEMENT COST (%)



On this benchmark, Generation's maintenance spend is below the lower boundary.

7.4.3 Conclusion on maintenance costs

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.

7.5 Other Opex

The cost category "Other Opex" contains all the operating costs that are not classified as either manpower or maintenance costs. It includes the following operating costs: Contractor Costs, Decommissioning Expenses, Environmental expenses, Materials Expense, Net Insurance Expense, Office and Site Operation Costs, Operating lease, consulting & travel, Other General Expenses and Recovery postings.

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

TABLE 50: TOTAL GENERATION OTHER OPEX

Other Opex (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Generation Licence Total Other Opex **[A]**	11 939	12 618	3 942	14 558	14 741	15 085	15 797	15 711
Abnormal: Koeberg Decomissioing Provision **[B]**	(705)	143	(10 255)	-	-	-	-	-
Normalised Generation Licence Other Opex [A] – [B]	**12 644**	**12 475**	**14 197**	**14 558**	**14 741**	**15 085**	**15 797**	**15 711**

TABLE 51: OTHER OPEX PER CATEGORY

Other Opex (R'm)	Actual FY2023	Projection FY2024	Projection FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY2029	Post Application FY2030
Contractor Costs	2 100	3 330	3 841	3 948	4 021	4 039	4 181	4 288
Environmental expenses	178	355	560	714	716	579	607	637
Internal Electricity costs	724	924	865	1 158	1 301	1 429	1 595	1 779
Materials Expense	1 457	1 333	1 380	1 406	1 441	1 451	1 541	1 634
Net Insurance Expense	3 877	4 597	4 303	4 212	4 355	4 536	4 741	4 016
Office and Site Operation Costs	1 837	2 138	2 388	2 414	2 426	2 440	2 512	2 601
Operating Lease, Consulting & Travel	888	995	1 109	997	762	916	950	1 061
Other General Expenses	4 016	539	621	592	616	615	649	674
Recovery Postings	(1 019)	(772)	(872)	(884)	(897)	(921)	(978)	(979)
Secondary Account Capitalisations	(1 414)	(963)	(0)	(0)	(0)	(0)	(0)	(0)
Total *Normalised* Gx Other Opex	**12 644**	**12 475**	**14 197**	**14 558**	**14 741**	**15 085**	**15 797**	**15 711**

7.5.1.1 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.

7.5.1.2 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.

7.5.1.3 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.

7.5.1.4 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.

7.5.1.5 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.

7.5.1.6 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 ageing generation fleet and maintenance activities that are postponed as these increase plant risks.

7.5.1.7 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.
- License 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

7.5.1.8 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 are 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

7.5.1.9 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

7.5.1.10 Recovery Postings

All costs incurred by different laboratories for the testing and analysis of water, coal, oil, corrosion etc transferred to primary energy accounts for example water treatment etc.

7.6 Other Income

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

Other income is difficult to forecast with any degree of accuracy. The forecast for the next few years was done based on historical trends and is shown in the table below.

TABLE 52: GENERATION OTHER INCOME

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

7.7 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.

Generation has compared its operational performance against three international benchmarks with a **2023 base year comparison**:

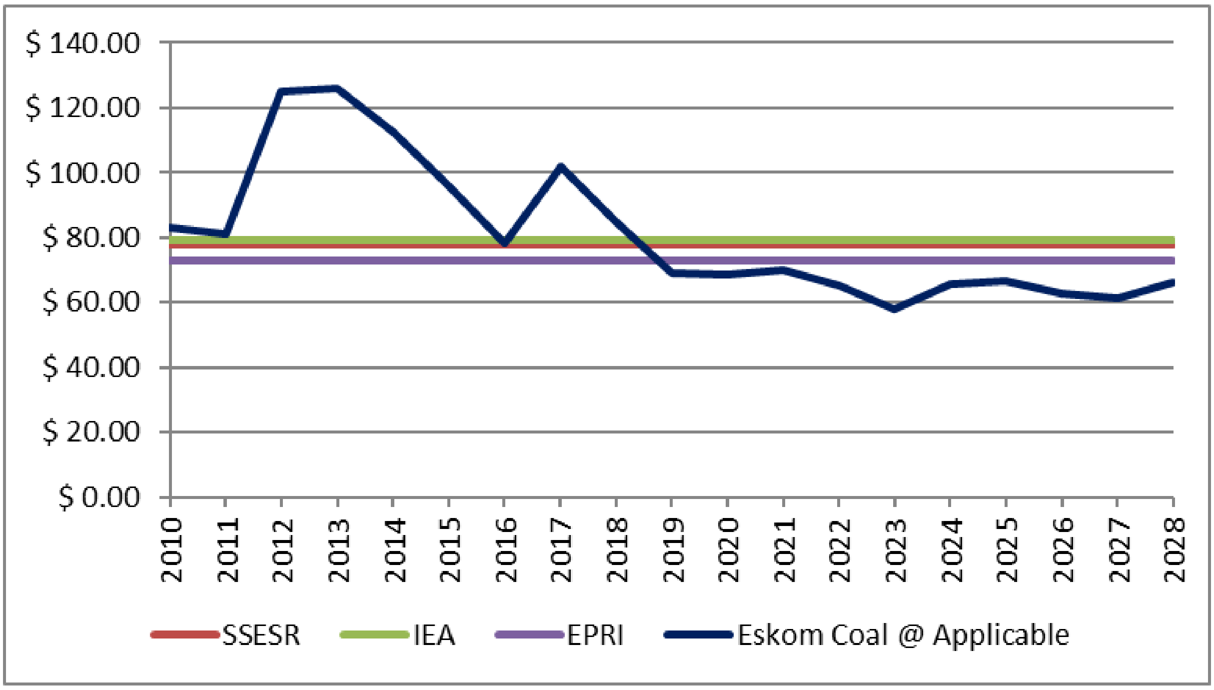
TABLE 53: BENCHMARK O&M COSTS

	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.

NB: Note that for purposes of this comparison, Generation includes Outage Capex as part of O&M.

FIGURE 35: BENCHMARK COMPARED TO REAL $/KW (COAL ONLY)



'Eskom coal @ applicable' refers to the applicable average exchange rate for that year based on Eskom's forecast.

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.

8 RAB, Return and Depreciation

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

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

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

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

TABLE 54: REGULATORY ASSET BASE (RAB) SUMMARY

GENERATION - REGULATORY ASSET BASE (R'm)	Decision FY2024	Decision FY2025	Application FY2026	Application FY2027	Application FY2028	Post Application FY 2029	Post Application FY2030
Depreciated Replacement Costs (DRC)	677 641	633 995	611 670	572 153	533 036	494 789	457 585
Asset transferred to commercial operation post valuation date	45 961	28 757	224 221	256 027	281 300	287 587	325 403
Work Under Construction (WUC)	40 712	32 137	41 750	49 359	54 378	46 452	61 251
Net Working Capital	32 321	41 505	42 007	19 423	18 003	23 015	23 981
Assets Purchases	128	171	1 221	1 480	1 717	1 374	1 099
Assets funded upfront by customers	-	-	-	-	-	-	-
Total Regulatory asset base (RAB)	**796 763**	**736 565**	**920 870**	**898 442**	**888 434**	**853 216**	**869 319**
Average RAB		**766 664**	**828 717**	**909 656**	**893 438**	**870 825**	**861 267**

8.1 Regulatory Asset base components:

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

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

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

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

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

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

8.2 Depreciated replacement costs

The roll forward of the depreciated replacement costs for MYPD6 as shown below is based on MYPD5 approved values. The depreciation is based on the remaining useful life. The R507bn added back in 2024 is because of the decision from the Court that the Energy Regulator was not supposed to deduct this amount in the 2023 Nersa decision.

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

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

8.3 Work under construction (WUC)

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

- **Expansion** – this is capital expenditure to create additional capacity to meet the future anticipated energy demand forecast.

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

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

8.4 Depreciation

The depreciation is the cost of usage over the life of the asset. This is generally a proxy for the recovery of the capital portion of the investment made in the infrastructure.

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

TABLE 56: GENERATION DEPRECIATION

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

8.5 Return on Assets

The return on asset included in the MYPD6 application is shown in the table below. Generation is applying for 4%, 5% and 6% ROA for 2026, 2027 and 2028 respectively.

TABLE 57: GENERATION RETURN ON ASSETS

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

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

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

9 Capital Expenditure

9.1 Introduction

The MYPD methodology allows for the capital related costs to be recovered over the life of the assets through return on assets and depreciation. Thus, it is clarified that capital expenditure is not included in the allowed revenue regulatory formula.

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

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

TABLE 58: ESKOM CAPITAL ALLOCATION PRINCIPLES & GUIDELINES

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

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

TABLE 59: GENERATION CAPEX SUMMARY

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

9.2 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 Kusile as well as Generation Coal and Clean Technology projects which includes refurbishment projects as well Emissions projects.

9.3 Outage and Technical Plan Capex

Outage and technical plan capex is critical to sustain the reliability of the power stations in the medium to long term. Because of a lack of funding (mainly because of sub-cost reflective tariffs) and system space (because of the constrained country capacity situation), reliability outages and projects cannot be executed as required, thereby affecting the underlying health of plant and consequently plant reliability. This may ultimately reduce the availability of generating plant which 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 utilises a capacity planning process that optimizes the planned outages on a continual basis, based on the prevailing constraints and outage priority.

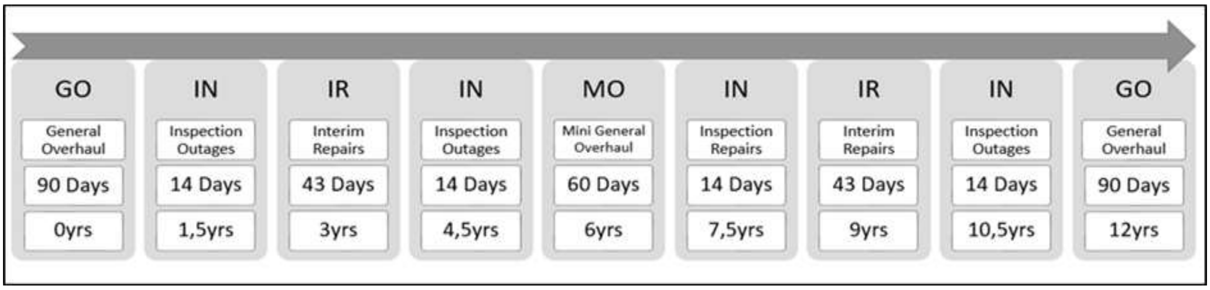
- The capacity planning process requires, as its main input, the long-range demand forecast less the forecasted renewables contribution (residual demand). This is the demand expected to be supplied by Eskom and the Gas IPP's. The daily peak demand is then used for capacity planning.
- The next important 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 (~ 47 000 MW) less the sum of the load forecast, expected UCLF and reserve margin determines the available outage capacity per day. Outages are then slotted into these spaces and optimised **to minimise the capacity shortfall (i.e., to reduce or minimise the risk of load shedding)**.

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

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

Figure 36: Tutuka Outage Philosophy cycle



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

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

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

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

The same allocation process has been applied to Technical Plan projects with the current prioritised projects (composed of all mandatory and those sustaining and strategic projects with a high certainty of execution, therefore a further refinement of the sustaining and strategic projects). Effectively all betterment technical plan projects have been deprioritised. The impact of not executing the sustaining and strategic projects will compromise the pace of the Generation Operational Recovery which has begun showing positive results in the current financial year.

9.3.1 Future Fuel Capex

9.3.1.1 Coal future fuel

See Section 6.6

9.3.1.2 Water future fuel

See Section 6.6

9.3.1.3 Nuclear future fuel

See Section 6.7.3

10 Environmental Compliance

The environmental clause in the Bill of Rights sets the context for environmental protection, providing for an environment which is not harmful to health and well-being and for ecological sustainable development. The National Environmental Act and several Strategic Environmental Management Acts (SEMAs) give effect to the environmental right in the Constitution. The development of environmental legislation has resulted in new and more stringent requirements which Generation is obligated to respond to in order to continue operating its power stations. Given the nature of Generation's activities, these requirements are far reaching; they affect all the divisions and subsidiaries in some manner, including air quality, protection of the natural environment and biodiversity, water use and preventing pollution of water resources, general and hazardous waste management, the utilisation of ash and licensing processes. These legislative requirements are enforced through licences and permits. They lead to operational and capital expenses. To retain the licence to continue to operate, these expenses must be allowed for in the tariff, preferably in a manner which separates non-negotiable statutory requirements from refurbishment and maintenance expenses.

The most significant environmental costs over the next 10 years are for air quality, air quality offset, ash dams/dumps and water management.

10.1 Emission Reduction Plan

Minimum Emission Standards were published in 2010 in terms of the National Environmental Management: Air Quality Act, 2004 requiring facilities to comply with "existing plant" standards by 2015 and for existing plants to comply with "new plant" standards by 2020. There are three pollutants which Generation is required to control: sulphur dioxide, nitrogen oxide and particulate matter. Applying new plant standards to existing/aged plant is technically challenging and costly.

Generation has developed an Emission Reduction Plan prioritising the implementation of particulate matter projects as it is the pollutant which is in general non-compliance to ambient air quality standards in the areas in which coal stations operate. In terms of nitrogen oxide which complies to ambient air quality standards and Eskom is implementing interventions at only four of the most polluting stations. Ambient sulphur dioxide levels are also in compliance to ambient air quality standards and as such Eskom has identified only Kusile and Medupi for emission retrofits for this pollutant. Most of the planned emission reduction projects will be completed by the legal deadline of 2025 and work to fast track those delivered later than this date is underway.

In May 2024 Eskom received a response to its request for legal postponement and suspension from the MES requirements. The appeal decision will allow stations operating until 2030 to continue using existing emission technologies until they shutdown. For stations operating post-2030 Eskom is required to submit a further exemption application motivating for legal indulgence from full compliance to the MES. If Eskom fails to obtain exemption and the existing MES decision stands it will require an estimated R 300bn capital cost over 10 years. There is also a risk of up to 19000 MW not having a licence to operate from March 2025.

In parallel to the programme to reduce air emissions at coal fired power stations, Generation is required to embark on an air quality offset project in communities surrounding Generation power stations. This project will reduce the most significant contributor to health impacts in low-income communities. The offset project is a legal requirement enforced through the approval of the postponement application and as a condition of Atmospheric Emission Licences.

10.2 Air Quality Offsets

Generation is required to implement air quality offsets as a condition of the approved Minimum Emission Standards postponements, and a condition of all Highveld power stations' Atmospheric Emission Licences. Air quality offsets are designed to reduce human exposure to harmful levels of air pollution by reducing emissions from local sources, like domestic coal burning and waste burning.

FIGURE 37: OPPORTUNITIES FOR AIR QUALITY OFFSETS: REDUCING LOCAL WASTE BURNING (LEFT) OR DOMESTIC COAL BURNING (RIGHT)

Generation's air quality offset programme is intended to reduce emissions from coal/wood burning in Mpumalanga (through insulating houses and swopping existing coal stoves for LPG heaters and combined electric and LPG stoves), and from local waste burning in the Vaal.

Phase 1: *Lead implementations* at KwaZamokuhle (next to Hendrina) and Ezamokuhle (next to Amersfoort) have progressed with 4287 households out of a planned 5800 being retrofitted as of the end of April 2024. Five waste clean ups to reduce waste burning in Sharpeville have been completed by the end of April 2024. Some 211 local people have been employed in the project to date and approximately R40m of local spend has been recorded.

Phase 2: *Full implementation*. This will see the rollout continue to a planned 36 000 households. Contracting for this work is progressing with several key delivery and monitoring contracts awarded.

The successful implementation of air quality offsets promises to meaningfully improve the air quality of the air breathed by thousands of people and should improve the health and create employment opportunities for many.

10.3 Ash dam/dump extensions

Ash dams and dumps are a key component in the generation of electricity. Without an ashing facility the power station cannot continue to operate. Generation produces approximately 30 million tonnes of ash annually, six to eight percent of which is recycled. The remaining ash is sent from the power station and disposed of in an ash dam or dump.

In terms of the National Environment Management Waste Act (NEMWA), ash is classified as a hazardous waste. Prior to the promulgation of the Act there was no requirement for a Waste Management Licence (WML) for ashing facilities. However, the extension of ashing facilities beyond their original planned ashing footprint triggered the requirement for a WML which in turn triggered the requirement for lining the ashing facilities. Since Generation was not able to install the lining immediately on dry ashing facilities, the DFFE, at Generation’s request, granted an exemption to install the lining within four/five years of receiving the WML.

10.4 Water management

Generation is one of the largest industrial consumers of fresh water in South Africa, accounting for approximately 2-3% of the country’s total water consumption annually. The reliability of water infrastructure and the availability and quality of water have a significant impact on Generation’s ability to produce electricity and to use water efficiently. In terms of the National Water Act 36 of 1998 and the National Water Resource Strategy 2, Generation is required to use water efficiently, to comply with licence conditions and ensure that our activities do not cause or potentially lead to pollution of water resources.

Generation's Water Strategy was developed to set the direction on water-related issues and address compliance. The strategy outlines the key activities required to ensure efficiency and compliance, these include the lining of all dirty water dams, design and construction of separate dirty and clean water systems, the installation/upgrade of water treatment plants.

11 Conclusion

For Generation to be able to continue to operate and maintain its assets in a reliable state, it is imperative that it is allowed the revenue in order to do so, considering that the Eskom tariff has been sub cost reflective for a number of years, which largely contributed to the dire state of affairs Generation currently finds itself in.

Generation's operating costs is in line with all of the international benchmarks which serves to highlight the reasonability of Generation's operating costs. 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.

The total primary energy is inclusive of Eskom primary energy, carbon tax and the environmental levy. In order for the system operator to meet the demand, the dependence on IPPs has diminished. Thus, the additional dependence on Eskom's coal-fired power stations to fill this gap. It also results in securing more expensive coal to ensure continuity of supply. The primary energy costs increases annually over the MYPD 6 period mainly as a result of the implementation of the Carbon Tax.

The difference in energy to be secured from IPPs has dropped tremendously from what was originally envisaged by the Government Departments. This corresponds to shortfalls of approximately 26 TWh (FY2026), 42 TWh (FY2027) and 33 TWh (FY2028). This is approximately 12% (FY2026), 20% (FY2027) and 15% (FY2028) of the total energy supply that Eskom needs to accommodate. This has far-reaching impacts on Eskom's operations, and by implication, efficient costs.

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

It is thus submitted that a well-motivated Generation application has been made to support the continued delivery of energy in the absence of further national capacity.