Eskom	Emission Dispatch Prioritization Strategy	Date: 20 Jan. 2026
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Emission Dispatch Prioritization Strategy

PRODUCTION OPTIMISATION

GENERATION: PRODUCTION & SALES

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REV A

DRAFT FOR STAKEHOLDER COMMENT

	Compiled by:	Reviewed by:	Supported by:	Approved by:
Name:				
Date:	16/03/2026	16/03/2026	17/03/2026	19/03/2026
Signature:				
Designation:	Chief Advisor Production Optimisation	Chief Advisor Production Optimisation	Senior Manager Energy Management	General Manager Production & Sales

Table of Contents

1. Abbreviations

AN	Arnot
ASP	Ancillary Services Payment
BESS	Battery Energy Storage System
CAV	Cost Adder Value
CBA	Cost Benefit Analysis
CD	Camden
CO_2	Carbon Dioxide
CP	Capacity Payment
CSP	Concentrated Solar Power
DFFE	Department of Forestry, Fisheries and the Environment
DV	Duvha
EAF	Energy Availability Factor
EDEM	Eskom Dynamic Energy Market
EP	Energy Payment
ESI	Electricity Supply Industry
ETS	Emission Trading Scheme
EU	European Union
GHG	Green House Gases
GV	Grootvlei
HD	Hendrina
IR	Instantaneous Reserve
IRP	Integrated Resource Plan
KD	Kendal
KR	Kriel
KS	Kusile
LT	Lethabo
MD	Medupi
MES	Minimum Emission Standards
MJ	Majuba
ML	Matla

MT	Matimba
NACAA	National Association of Clean Air Agencies
NECA	National Environmental Consultative and Advisory
NERSA	National Energy Regulator of South Africa
NOx	Nitrogen Oxide
NTCSA	National Transmission Company South Africa
OCLF	Other Capability Loss Factor
PCLF	Planned Capability Loss Factor
PM	Particulate Matter
PPA	Power Purchase Agreements
SDR	Scheduling & Dispatch Rules
SMP	System Marginal Price
SMP	System Marginal Price
SO	System Operator
SO_2	Sulphur Dioxide
SOC	State Owned Company
SRMC	Short-Run Marginal Cost
TT	Tutuka
UCLF	Unplanned Capability Loss Factor
VO&M	Variable Operating and Maintenance
YTD	Year to Date

List of tables

Table of figures

2. Executive Summary

Emanating from the decision issued by the Department of Forestry, Fisheries and the Environment (DFFE), Eskom was granted an exemption under the Minimum Emission Standards (MES) on 31 March 2025[1]. This exemption was granted until 1 April 2030, in particular for eight power stations namely, Lethabo, Kendal, Tutuka, Matla, Duvha, Majuba, Matimba, and Medupi. As part of the conditions attached to this exemption, there is a requirement of reducing the coal burnt at each power station thereby reducing emissions, specifically the amount of SO_2 emitted into the atmosphere. The condition stated that Eskom should investigate how a SO_2 emission price in R/kgSO_2 can meaningfully be included in its Dispatch Prioritization Strategy (DSP). Additionally, Eskom must develop a proposed SO_2 emission Dispatch Prioritization Strategy, publish for stakeholder comments, and submit the final report with all comments.

To meet this requirement, Eskom undertook a detailed analysis of how SO_2 emission cost influences operational dispatch outcomes and system costs. The evaluation considered various options including separate priority area (PA), combined (PA), additional cost adder, multi-objective optimization and cap-and-trade. These options were evaluated considering the amount of coal burnt, SO_2 emitted and the overall impact on the system marginal price (SMP) and system cost.

The results indicate that incorporating SO_2 emission pricing leads to only a marginal decline in SO_2 emissions while imposing substantial additional system costs. The observed reduction in SO_2 emissions is largely driven by the increasing integration of renewable energy into the system which reduces the reliance on coal fired stations resulting in a subsequent decrease in SO_2.

Emission reductions achieved to date are largely attributable to structural system changes — such as increased renewable penetration — rather than plant-level interventions, suggesting the need for enhanced abatement strategies at specific stations with high SO_2 intensities. It is also noted that optimization for SO_2 reduction could result in an undesirable increase in CO_2 emissions as production is shifted to more CO_2 polluting stations.

This report outlines a suggested approach for developing an SO_2 Dispatch Prioritization Strategy that balances environmental compliance, system security, and economic sustainability. It provides a foundation for stakeholder engagement and enables Eskom to meet the MES exemption condition requiring submission of a strategy report to the Minister.

3. Introduction

Eskom filed an application for exemption from the MES for each of its eight coal-fired power stations: Duvha, Kendal, Lethabo, Majuba, Matimba, Matla, Medupi, and Tutuka[2]. The exemption was granted by the DFFE on 31 March 2025, subject to specific conditions. Of particular relevance to this report, one key condition stipulates a reduction in the volume of coal burnt, thereby achieving a decrease in sulphur dioxide (SO_2) emissions.

In the exemption application, Eskom stated that:
'*the existing coal fired power stations are expected to provide additional flexibility to the system through increased variability in load following mode of operation, as well as providing back-up to the variable intermittent non-dispatchable renewable technologies, as well as providing ancillary services, inertia, etc which are not provided by the inverter-based renewable technologies. This essentially results in lower running load factors for these stations as the renewable energy sources will be given priority dispatch over the fossil-fuelled stations.*' [1]

In its applications, Eskom described a Dispatch Prioritisation Strategy (DPS) of renewables, which will reduce SO_2 emissions. In this strategy, Eskom intended not to run plants at maximum loads but rather limit to those required for system adequacy, resulting in reduced coal burnt. Thus, reducing the SO_2 emissions overall.

As a result, DFFE has instructed Eskom to investigate how a SO_2 emissions price in R/kgSO_2 can meaningfully be included in its Dispatch Prioritisation Strategy. The objective of the price shall be, over time, to influence dispatch decisions such that those plants whose SO_2 emissions are having the worst impact on health are more costly to dispatch. DFFE further highlighted the guidelines in the proposal design as summarised below:

1. In the context of exemptions from a concentration - based regulatory regime, a pollutant price condition can only be imposed on and implemented

by Eskom. This is in contrast to the conventional implementation of a price in the form of a tax or a levy, which would require the involvement of National Treasury and regulatory reform.

2. The SO_2 price need not be a real cost to Eskom Generation, nor need it be reflected as allowable revenue in the tariff decision-making process yet. However, over time the price should be able to evolve to achieve both of these aspects.
3. There may be regulatory considerations in designing the price that need to be taken into account, including in the regulation of the coal plant bid costs in the transitioning market, and their vesting contracts with Central Purchasing Agency.
4. Whether the calibration of the SO_2 price should be plant-specific, uniform across plants, or whether different penalty levels should be applied to plants in different Priority Areas, given the differing health impacts, must be considered.
5. Consideration of how a SO_2 price might work under are quality regulatory reform as described in National Environmental Consultative and Advisory (NECA) Forum 2024 report.

According to DFFE, the analysis at minimum must:

1. Detail how the price can influence System Operator dispatch decisions at the margin under transitional and future market structures.
2. Discuss what processes are required to ensure any adaptation of the price mechanism during the transition to the market structure.
3. Identify which processes within Eskom need to be exposed to the price to ensure it is fully reflected in dispatch decisions.
4. Include consideration of a range of price calibrations for their impact on system level outputs such as adequacy of supply, electricity system cost and GHG emissions.
5. Recommend an appropriate starting penalty level, design and mechanism, and comment on the potential for escalation over time.

Following these guidelines, Eskom has conducted an analysis of adding SO_2 pollutant price in the dispatch decisions which will be discussed in detail in this report.

4. South African Electricity Market

Eskom operates as a vertically integrated, state-owned utility and is undergoing structural unbundling into three distinct subsidiaries namely Generation, Transmission, and Distribution to align with market liberalization objectives. On 1 July 2024, National Transmission Company of South Africa (NTCSA) officially started operating as a subsidiary of Eskom Holdings State Owned Company (SOC)[3]. This separation is designed to facilitate competitive generation, enable non-discriminatory grid access, and establish an independent system operator, thereby improving operational transparency and efficiency within South Africa's Electricity Supply Industry (ESI). Energy trading between Eskom Generation and the NTCSA currently operates under a regulated framework through annual Power Purchase Agreements (PPAs) and currently governed by Scheduling and Dispatch Rules (SDR) approved by National Energy Regulator of South Africa (NERSA). Each power station signs a PPA with NTCSA that sets out pricing arrangements along with the terms and conditions governing energy transactions, ensuring structured and compliant trading while laying the groundwork for a future competitive market environment which will be governed by Market Code upon approval by NERSA.

A power station generating unit's revenue is a summation of the capacity, energy and ancillary services payments. The Capacity Payment (CP) is a fixed payment that is paid for each period for a unit of MW of available capacity. It includes fixed charges such as repayment of the principal and interest on the debt used to construct the facility, return on equity capital invested, fixed operating and maintenance costs and fixed costs related to fuel supply and transportation. The Energy Payment (EP) is paid for each period for each unit of energy sent-out during that period. It includes costs that vary with production such as variable fuel costs and variable operating and maintenance (VO&M) costs. Ancillary Services

Payment (ASP) covers various reliability services essential for system stability. Instantaneous, Regulating, and 10-minute reserves are procured through the day-ahead reserve markets, with scheduled capacity compensated at the reserve System Marginal Price (SMP). Islanding and Black Start capabilities are remunerated for both fixed and variable costs associated with maintaining and testing these services; however, if a unit fails to demonstrate compliance during testing, full payment may be withheld.

A generator's source of revenue is calculated using equation 1 below. It is a summation of the capacity, energy and ancillary serves payments.

$$\boldsymbol{Generator\ Revenue} = \boldsymbol{CP} + \boldsymbol{EP} + \boldsymbol{AS} \qquad \textit{Eq. 1}$$

Generator performance is intrinsically linked to dispatch priority within the power system. Revenue streams depend on the volume of energy dispatched and prevailing market prices; therefore, any reduction in dispatch frequency or load factor directly decreases income. Operational stability is also affected, as lower utilization disrupts optimal maintenance cycles and reduces efficiency, potentially increasing forced outage risks. Over time, persistent low dispatch priority can erode economic viability, particularly for generators with high fixed costs, making them financially unsustainable without compensatory mechanisms such as capacity payments or regulatory support.

Scheduling and Dispatch Rules and Market Code states that Day-ahead Market participants shall provide a daily submission of the expected availability or maximum consumption of each trading unit and the incremental price associated with the dispatch of these trading units for each trading period. They further state that the dispatch algorithm's objective shall be to minimize the total cost of generation required to meet the expected demand, constrained by the reserve requirements and technical capabilities of trading units. The Market Operator shall determine an unconstrained schedule which determines the optimal dispatch for all trading units for each period of the dispatch day, taking into consideration submissions, reserve requirements, interconnection schedules, and the production and consumption prices and parameters of trading units. Ideally, the System

Operator would want to minimize the costs of meeting demand by scheduling a generating unit based on merit order. The least cost-generating units would be scheduled first, and then the next least cost, and so forth until enough generation is scheduled to meet the expected demand.

5. SO2 Dispatch Prioritization Strategy (DSP)

5.1 Existing Dispatch Methodology

Coal-fired power stations remain the predominant source of electricity generation in South Africa, providing critical system inertia, frequency response, voltage regulation and short-circuit strength which underpins grid reliability and stability. Although renewable energy sources like solar PV and wind are increasing rapidly, their inherent intermittency limits their ability to provide consistent baseload power. Consequently, coal generation remains a critical component of the grid, ensuring operational flexibility and supporting secure system performance.

The current economic dispatch methodology employed by the System Operator (SO) optimizes generation based solely on short-run marginal cost and system reliability, without incorporating environmental externalities such as sulphur dioxide (SO_2) emissions.

This results in cheaper stations being dispatched first and expensive ones last. This approach aims to minimize the total system cost by favouring cheaper generators and is a cornerstone of traditional economic dispatch models for the provision of affordable electricity. This cost-based approach is designed to ensure the most efficient use of available resources by minimizing the total cost of electricity generation across the system. This is achieved by placing generators in a merit order system, ranking them in order of increasing SRMC. Therefore, stations with a low SRMC are ranked lower in the merit order thereby dispatched first and high-cost stations are ranked high resulting in them being dispatched last. Not incorporating emissions such as carbon dioxide (CO_2), particulate matter (PM), nitrogen oxides (NOx) and Sulphur dioxide (SO_2) in the dispatch order results in a dispatch profile that potentially favors low-cost, high-emission units, thereby increasing compliance risks under tightening air quality regulations. Therefore, incorporating SO_2 emissions into dispatch optimization introduces a multi-objective trade-off.

5.2 SO2 Dispatch Prioritization Strategy

In the FY2025 period, the total energy produced by Eskom amounted to 224 668 GWh with a net sent-out energy of 218 601 GWh. Coal production amounted to approximately 79.9%, underscoring the heavy reliance on coal as the main primary source of electricity. Figure 1 provides an overview of the energy produced. Nuclear power contributed 3.7%, providing a stable baseload, while peaking plants accounted for 3.4%, offering flexibility to meet peak demand. Independent Power Producers (IPPs) supplied 8.6% and international trader represented 4.3%, indicating a degree of dependence on external sources and Eskom Wind contributing only 0.1%.

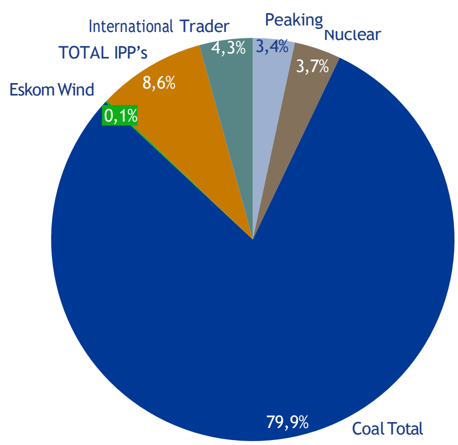


Figure 1: FY2025 energy production overview.

Overall, the existing electricity production portfolio is highly coal weighted, with a modest diversification from IPPs. 8GW capacity from coal fired stations will be shut down by FY2030. This will be partly offset by more renewable penetration and IPP gas projects together with the planned Ankerlig and Gourikwa OCGT to CCGT conversion. This effort will also aid in the reduction of coal energy production, effectively contributing to the reduction of SO_2 production.

In response to the DFFE request, a review of international methodologies for environmental dispatch was undertaken. By examining these global approaches, the aim is to identify strategies that could enhance compliance with environmental objectives while maintaining system reliability and operational efficiency within the South African context. There are several strategic approaches to mitigating pollutants, including the implementation of an emission pricing policy that internalizes environmental costs, the adoption of an environmental dispatch priority policy that ensures operational decisions explicitly account for air emissions, and the enforcement of a ranking order policy that prioritizes low-emitting resources over higher-emitting alternatives in the energy procurement process. Figure 2 illustrates a typical example of an environmental dispatch priority order in the United States.

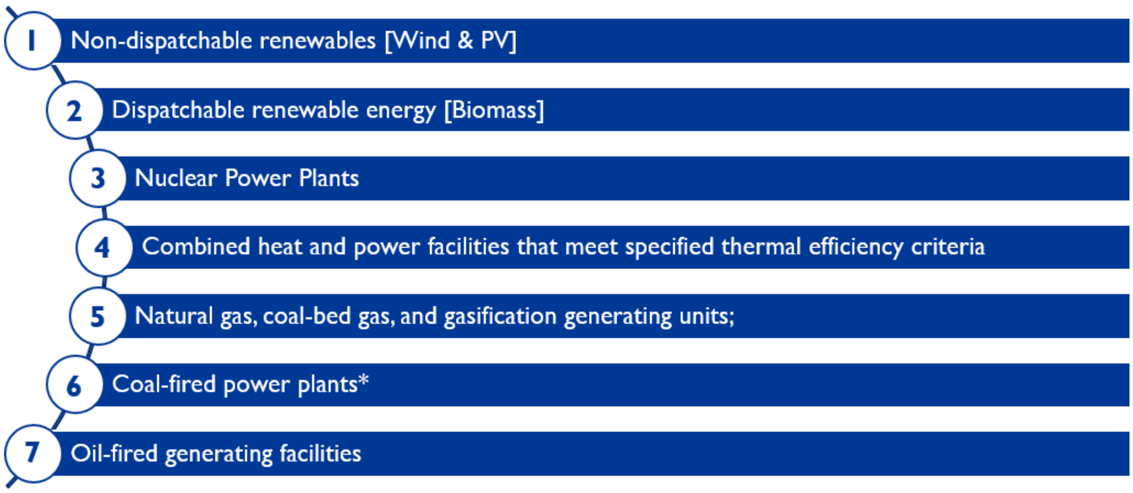


Figure 2: An Example of preferential Environmental Dispatch Priority Order in the United States.

The emission pricing policy is a market-based environmental mechanism designed to internalize the external costs associated with air pollutant emissions whereby generators are required to pay a fee for each unit of emissions produced, such as SO_2, NO_x, PM, or CO_2. This approach assigns a direct financial cost to pollution, thereby incentivizing cleaner and more efficient generation technologies. The drawback with this approach is that it may increase the variable operating costs of high emitting power stations thereby rendering them less competitive and potentially impacting the overall system economics.

The Environmental Dispatch Priority Policy is a strategy in which the system operator explicitly incorporates environmental criteria, primarily air pollutant emissions—into the dispatch decision-making process[4]. Unlike emission pricing, which places a monetary cost on pollution, this approach prioritizes cleaner generation resources by directly adjusting the dispatch order to reduce environmental and public-health impacts. This can negatively influence the overall system economics if cleaner generating units are more expensive thereby increasing generation costs.

The ranking order policy regulates the procurement of energy resources by utilities by establishing a predefined hierarchy that explicitly favours low-emitting resources over higher-emitting alternatives. This policy framework directs utilities to prioritise cleaner technologies such as non-dispatchable renewables (wind and solar), dispatchable renewables, nuclear, and high-efficiency cogeneration— before considering higher-emission fossil-fuelled generators, including coal and oil-fired units. However, implementing this policy presents several challenges: it may require legislative or regulatory amendments to permit preferential procurement, can necessitate transitional measures to maintain system reliability as cleaner but less dispatchable resources are integrated, and may introduce system-economic inefficiencies where high-priority low-emission resources are not cost-optimal. Collectively, these drawbacks highlight the need for careful regulatory alignment and operational planning when integrating ranking-order mechanisms.

Environmental Dispatch Prioritization Strategy (DPS) is a strategy in which environmental and public health variables are priced and included as part of a generator's operating costs – thereby affecting their dispatch order. At its core, the environmental DPS aims to lower the amount of pollutants due to coal generation by incorporating the pollutant cost into a generator SRMC, thereby influencing the dispatch order ranking. This will result in recalculated, imputed cost which has both the generator's variable operating costs and environmental pollutant cost affecting the generator's dispatch ranking. In this report, the focus is on reducing the SO_2, therefore only the SO_2 cost implications were factored in.

6. Methodology

In the short-to-medium term, production optimization involves assessing the balance between supply and demand on an hourly basis, considering all known constraints, whether technical or non-technical. The optimization is done through the simulation technique using PLEXOS®[1] simulation tool on an hourly unit commitment and economic dispatch. The optimization includes an hourly demand, supply side options which includes Eskom supply, IPP supply as well as International Imports. Assumptions used in this study are based on the FY2027 Preliminary Corporate Plan will be discussed below. The study covers the period of five years from FY2027 to FY2031. Five different options or scenarios were explored to address the reduction in coal burnt.

6.1 Energy Forecast

Energy forecast is based on Eskom sales forecast, international sales forecast, Transmission and Distribution losses excluding pumping requirements as well as charging requirements. The energy forecast indicates the decline in energy sales over-time which follows the previous year's trend. The sharp decline in FY2031 is based on projected Mozal contract being extended until March 2030. However, if Mozal contract is not extended, the decline may be realised earlier in FY2027. Eskom's energy forecast differs from that of the Integrated Resource Plan (IRP). The IRP forecast is based on South Africa's national demand, (Figure **3**) illustrates the Eskom 5-year energy forecast.

[1] PLEXOS® is a powerful energy market simulation engine providing analytics and decision-support to modelers, generators, and market analysts— offering flexible and precise simulations across electric, water, gas and renewable energy markets.

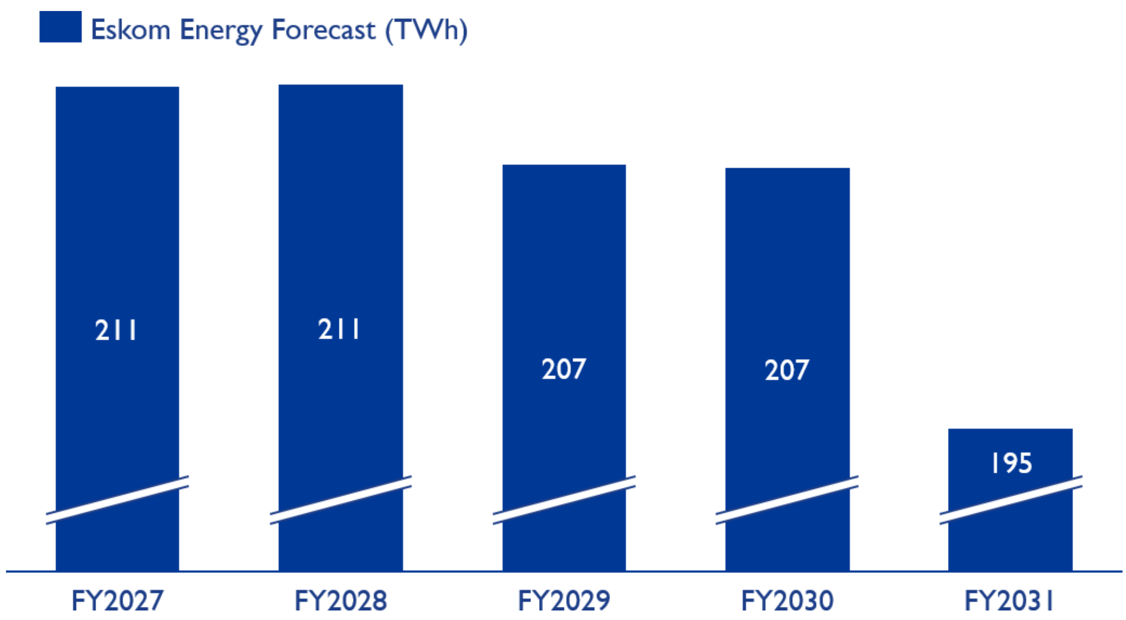


Figure 3: Eskom 5-year energy forecast.

6.2 Eskom Plant Performance

Eskom has experienced a declining plant performance over the past years with the lowest EAF of 55% by the end of FY2024. The turnaround was achieved in FY2025 with an EAF of 61%. The year-to-date (YTD) EAF is 64.5% as of 16 January 2026, with PCLF of 11.4%, UCLF of 23.6% and OCLF of 0.42%. Going forward, Eskom plant performance is projected to improve over the next five years from 68% in FY2027 and achieving 72.5% by FY2031 as shown in (Figure **4**).

Figure 4: Projected EAF for the next 5 years.

6.3 Eskom Generation Capacity

Eskom's generation capacity is projected to decrease by approximately 8 GW by FY2030, following the scheduled shutdown of Camden, Grootvlei, Hendrina, Arnot, and Kriel power stations. This reduction marks a significant shift in the energy supply landscape underpinning the need for alternative sources such as renewables, battery energy storage systems, baseload supply and independent power producers (IPPs) dependent on the system requirements.

6.4 Independent Power Producers Capacity

The Independent Power Producer (IPP) capacity plan reflects a significant expansion from 7,927 MW in FY2026 to 19,525 MW by FY2031, driven primarily by renewable energy and storage solutions. Renewables account for the largest share, growing from 6,772 MW to 13,427 MW, with solar PV contributing the most at 7,222 MW, followed by wind at 5,713 MW. Battery Energy Storage Systems (BESS) emerge as a critical component, adding 1,745 MW to enhance grid stability. While gas remains a strategic addition with 2,000 MW in FY2030, the overall trend underscores a strong commitment to decarbonization and energy diversification. This trajectory positions the system for improved reliability and sustainability, with peak growth expected between FY2029 and FY2030. These figures will continuously change due to projects delays and other considerations. The year-on-year growth is illustrated in the table that follows (Table **1**).

Table 1: IPPs and renewables capacity.

IPPs		FY2026	FY2027	FY2028	FY2029	FY2030	FY2031	Total
	Existing Capacity (MW)	New Capacity (MW)						
DoE Peakers	1005							**1005**
RMP	150	150	128					**428**
Emergency Gen.		160	210					**370**
Standard Offer		150	350	200				**700**
IPP Gas Programme						2000		**2000**
BESS			513	1232				**1745**
Total	**1155**	**460**	**1201**	**1432**		**2000**		**6248**
Renewables								
Wind	3609	504				1600		**5713**
PV	2512	270	240	640	3560			**7222**
CSP	600							**600**
Hydro	18							**18.02**
Landfill Gas	8							**7.56**
Biomass	25							**25**
Total Renewables	**6772**	**615**	**240**	**640**	**3560**	**1600**		**13427**
Total New IPPs		**925**	**1441**	**2072**	**3560**	**3600**		11598
Total Cumulative	**7927**	**8852**	**10293**	**12365**	**15925**	**19525**		

6.5 SO_2 Emission Price Determination

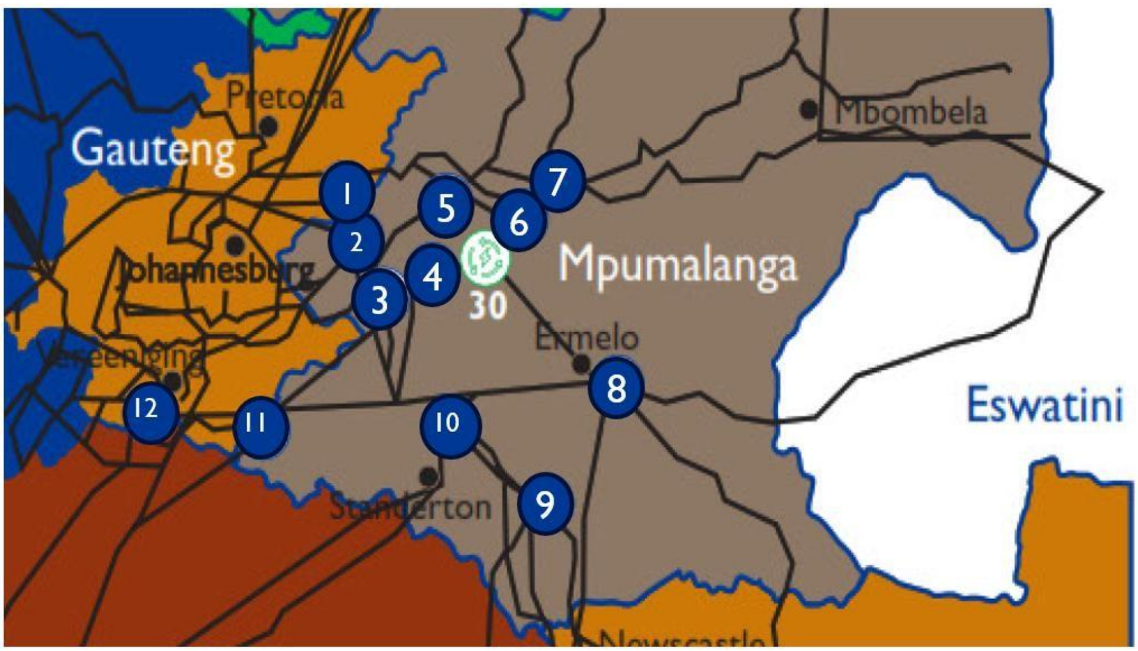
The approach was to establish the SO_2 emissions price in R/kgSO_2 to be applied as the cost adder to the current variable cost of coal fired stations. For this purpose, the study conducted by Prime Africa Consult (2024) was used to establish the R/kgSO_2.

Prime Africa Consult conducted a study which investigated the health benefits and implementation costs of mitigating air pollution emissions from Eskom coal-fired power stations for both in the Highveld and Waterberg priority areas. The Highveld PA (Figure **5**) consists of power stations in Mpumalanga (Arnot, Camden, Duvha, Grootvlei, Hendrina, Kendal, Kriel, Majuba, Matla, Tutuka and Kusile) and Gauteng (Lethabo). Kusile power station is currently fully compliant with the MES. Arnot, Camden, Grootvlei, Hendrina and Kriel are currently earmarked for shutdown by 2030 and therefore granted suspension for MES compliance in May 2024 until their shutdown dates. The Waterberg PA consists of Medupi and Matimba power stations (Figure **6**).

From the cost benefit analysis (CBA) study that was conducted by Prime Africa consultants, the total number of the population in the vicinity of the power stations and the associated SO_2 health impact cost rand value was obtained. The annual SO_2 emitted by each power station and annual energy produced for FY2025 figures were calculated and used to formulate the base case which led to the derivation of the health cost per unit of energy sent out and SO_2 emitted (Table **2**).

Table 2: Calculated SO_2 emission price (R/Ton) (2024 CBA figures)

	Highveld PA	**Waterberg PA**	**National**
Health Impact Cost ®	1 640 211 739	26 544 728	1 666 756 467
FY2025 Actual SO_2 (Tons)	1 078 372	493 677	1 572 048
SO_2 emission price (R/Ton)	1 521	54	1 575



1. Kusile	2. Kendal	3. Matla	4. Kriel	5. Duvha	6. Hendrina
7. Arnot	8. Camden	9. Majuba	10. Tutuka	11. Grootvlei	12. Lethabo

Figure 5: Geographical layout of power stations in Highveld PA.

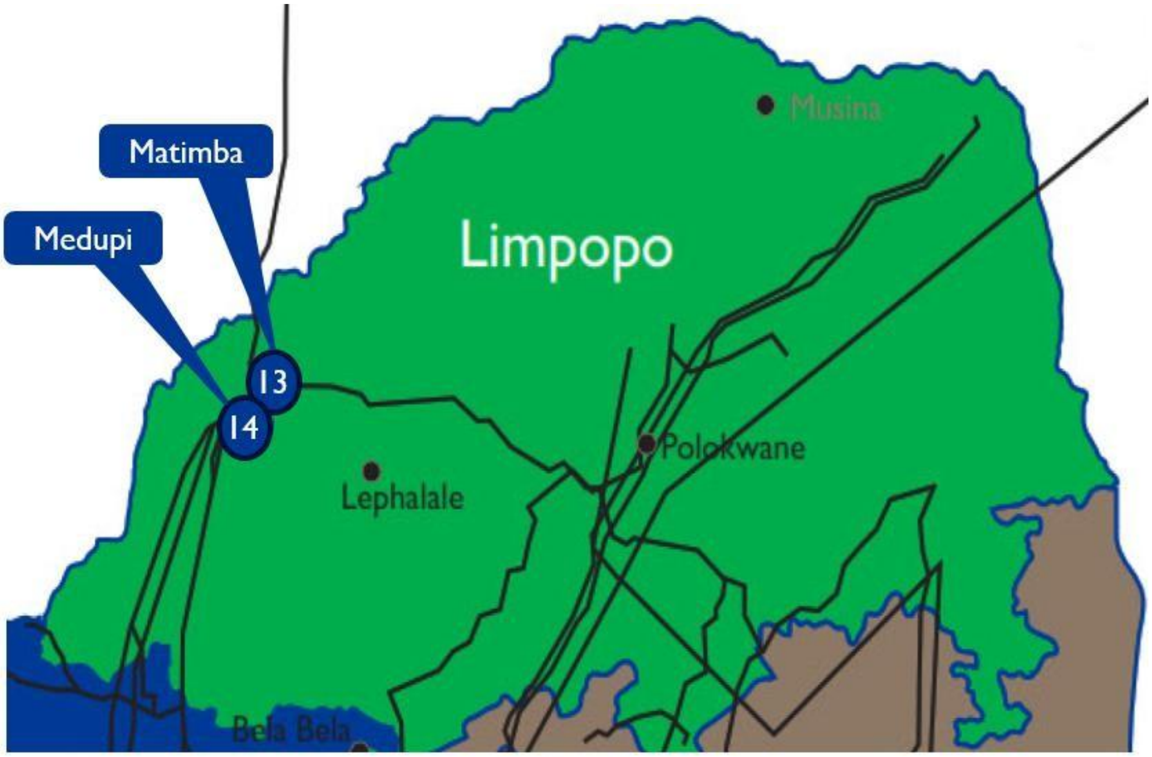


Figure 6: Geographical layout of Waterberg PA with power stations.

The SO_2 emission rates for each power station and dispatch order can be seen below (Table **3**). Based on these emissions rates, Matimba and Medupi (cheaper stations) are the highest emitters of SO_2 (even though they still have the lowest health cost), whereas Kusile is the lowest emitter.

Table 3: FY2026 Merit order and SO_2 emissions rates.

Power Station	**FY2026 Merit Order**	**SO2 [Tons/GWh]**
Matimba	1	14.2
Lethabo	2	9.0
Medupi	3	8.8
Kendal	4	10.9
Kriel	5	8.8
Matla	6	8.9
Tutuka	7	11.9
Duvha	8	10.1
Kusile	9	3.1

Arnot	10	7.1
Majuba	11	13.8
Camden	12	10.0
Hendrina	13	11.6
Grootvlei	14	9.1

7. Dispatch Prioritization Strategy Options

Five options were considered and investigated as seen below (Figure 7). The first three options are similar in approach but differ in calculation of the cost value adder. The fourth option is based on exploring other methods of reducing SO_2 emissions while also minimizing cost of production. The fifth option explores international practices and strategies implemented by other countries in terms of SO_2 emissions reductions.

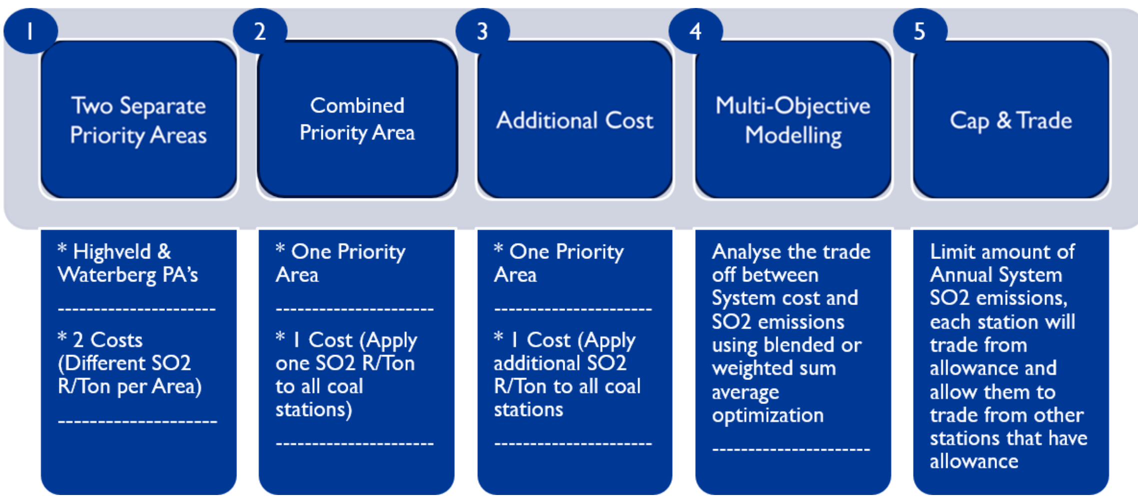


Figure 7: Five options considered.

The cost adder value (CAV) is calculated using equation 2 below.

$$CAV = SO_2 \; Relative\ Emission \left[\frac{Ton}{GWh}\right] \times \frac{SO_2\ Health\ Impact\ [R]}{Actual\ SO_2\ emitted\ [Ton]} \qquad \text{Eq. 2}$$

As an example, to calculate the CVA for Medupi:

$$CAV_{MEDUPI} = 8.8 \times \frac{26544727.86}{493677} = 475.3 \left[\frac{R}{GWh}\right] = 0.5 \left[\frac{R}{MWh}\right]$$

Next, the CAV is added to the base energy charge [R/MWh] to derive the new imputed energy charge value using equation 3. Table **4** illustrates the calculated CAV values.

$$\boldsymbol{Imputed\ Enegy\ Charge} = \boldsymbol{Base\ Energy\ Charge} + \boldsymbol{CAV} \quad \text{Eq. 3}$$

Table 4: Calculated CAV for all power stations [R/MWh].

Station	Base	Separate PA		National PA		Additional Cost	
	MO	CAV	MO	CAV	MO	CAV	MO
Matimba	1	0.8	1	22.3	3	93.1	3
Medupi	2	0.5	2	13.9	1	58.1	1
Lethabo	3	13.7	3	14.2	2	59.1	2
Kendal	4	16.6	4	17.2	4	71.7	5
Matla	5	13.5	5	14.0	5	58.4	6
Kusile	6	4.7	6	4.9	6	20.4	4
Majuba1_3	7	20.9	8	21.7	8	90.5	9
Majuba4_6	7	20.9	8	21.7	8	90.5	9
Tutuka	8	18.1	7	18.8	7	78.5	8
Kriel1_3 UG	9	13.3	9	13.8	9	57.7	7
Kriel4_6 OC	9	13.3	9	13.8	9	57.7	7
Duvha	10	15.4	10	15.9	10	66.5	10
Camden	11	15.2	11	15.7	11	65.6	11
Arnot	12	10.9	12	11.2	12	47.0	12
Grootvlei	13	13.9	13	14.3	13	59.9	13
Hendrina	14	17.7	14	18.3	14	76.4	14

Note: Merit order changes continuously with primary energy cost fluctuations.

7.1 Option 1: Two Separate PAs

This approach calculates the SO_2 health impact cost by treating Highveld and Waterberg Priority Areas separately, recognizing that population exposure and baseline air quality differ significantly between regions. The SO_2 health impact cost is R 1 640 211 738 and R 26 544 727 for Highveld and Waterberg priority areas, respectively.

7.2 Option 2: National PA

This approach consolidates the Highveld and Waterberg Priority Areas into a single system-wide metric, producing one combined population figure and one aggregate health impact cost for SO_2 externalities. The rationale is to simplify dispatch modeling by applying a uniform marginal damage coefficient across all units, rather than differentiating priority area.

- Total Health Impact Cost

$$R\ 1{,}640{,}211{,}738.88 + R\ 26{,}544{,}727.87 \approx R\ 1{,}666{,}756{,}466.75$$

$$National\ PA\ Cost\ Value\ = 1521 + 53.8 = 1574.8\ [{}^{R}/_{Tons}]$$

The resultant CAV values is as follows:

$$CAV_{MEDUPI} = 8.8 \times 1574.8 = 13921.03\ [{}^{R}/_{GWh}] = 13.9\ [{}^{R}/_{MWh}]$$

7.3 Option 3: Additional Cost

This option seeks to investigate and apply an additional amount that can be added to the overall national amount. The application of an additional amount of 5 000 [R/Tons] to the combined figure introduces a material change in the cost structure, which can significantly influence the merit order ranking.

$$Additional\ Cost\ Value\ = 5\ 000 + 1\ 574.8 = 6\ 574.8\ [{}^{R}/_{Tons}]$$

The resultant CAV values is as follows:

$$CAV_{MEDUPI} = 8.8 \times 6574.8 = 58121.03\ [{}^{R}/_{GWh}] = 58.1\ [{}^{R}/_{MWh}]$$

7.4 Option 4: Multi Objective Modelling

The objective function of the Plexos Simulation tool is to minimize the total cost of production while adhering to all known system constraints. This means the tool seeks the most cost-efficient way to dispatch generation resources, considering operational limits, demand requirements, fuel availability, emission limits, and other relevant constraints to ensure reliable and optimal system performance.

Multi-objective optimization is a powerful approach used to address problems where multiple, often conflicting, objectives must be considered simultaneously. In the context of SO_2 emission dispatch strategies, this means balancing goals such as minimizing emissions, reducing operational costs, and maintaining system reliability. Multiple objectives can be defined to analyze the trade-offs between competing goals using approaches such as Lexicographic (or hierarchical) optimization and blended (weighted average) optimization. Therefore, the multi-objective feature can be structured and implemented, which encapsulates the main properties of each objective.

7.5 Option 5: Cap & Trade

Environmental protection is generally pursued through two primary market-based mechanisms[5]. The more familiar approach to environmental protection would still be based on a system of required emissions permits, referred to as a cap-and-trade system. Each pollution source is given an initial emissions limitation. It can elect to meet this limit any way it sees fit rather than being required to install specific types of control technology. The source can reduce its pollution through energy conservation, product or process reformation, or any other means. Each source is expected to elect to reduce its pollution using the least expensive approach available to it. The other approach is one in which no limits are placed on each of the pollution that a source emits but in which each ton is taxed.

Cap and trade energy markets represent a market-based environmental policy designed to reduce greenhouse gas emissions and other pollutants, such as SO_2, in a cost-effective manner as demonstrated in the figure below. In a cap-and-trade system, a strict limit (cap) is set on the total amount of emissions allowed from all participating generators. These generators are then allocated or can purchase emission allowances, which they are free to buy and sell (trade) among themselves. This trading mechanism provides flexibility, enabling generators that can reduce emissions more efficiently to sell their excess allowances to others, thereby achieving overall emission reduction targets at the lowest possible cost.

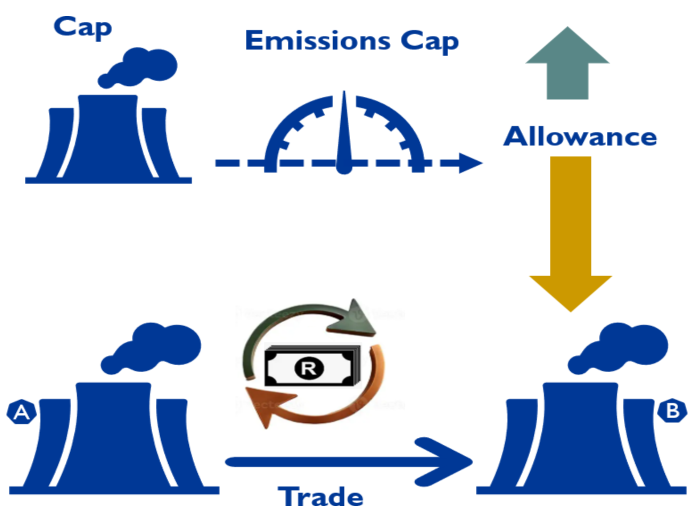


Figure 8: Illustration of a cap-and-trade system.

Cap and trade systems offer several important benefits and challenges for SO_2 emissions reduction. Some of the benefits are:

- They provide a cost-effective way to achieve environmental goals by allowing the market to find the lowest-cost emission reductions.
- Cap and trade offer much greater flexibility for utilities, as those facing high marginal abatement costs can purchase SO_2 allowances from utilities with lower abatement costs, optimizing overall system efficiency.

One of the main challenges in implementing a cap-and-trade system is determining the appropriate cap level. If the cap is set too high, it may permit excessive pollution, thereby undermining the system's effectiveness in achieving environmental objectives. On the other hand, if the cap is set too low, it can place undue burdens on generators, potentially causing economic strain and leading to higher costs for consumers. Striking the right balance is essential to ensure both environmental integrity and economic viability.

United States Cap and Trade System

The cap-and-trade approach began to be implemented in a small-scale way in the late 1970s and early 1980s in the United States. However, the large-scale successful application of cap-and-trade came in the 1990s. United States targeted to reduce emissions of sulphur dioxide by 50% in the eastern half of the country, as a result, cap-and-trade was created under which more than 100 large coal-fired power plants were given the ability to purchase excess emissions reductions generated by other plants that found it easy to reduce their sulphur dioxide. This resulted in reductions in sulphur dioxide emissions that have been both larger and faster than required by the law[5]. Some studies have been conducted that suggests using the system of flexible tradable allowances resulted in cost savings of between $150 million and $270 million compared to a uniform emission standard in the United State[6].

European Union Emission Trading Scheme (EU ETS)

An EPRI report indicates that the European Union Emissions Trading System was formally established in 2003 through the publication of the EU-ETS Directive, with the operational commencement of emissions-allowance trading following in 2005[7]. The EU-ETS has operated distinct phases with each phase incorporating new entities. Currently, the EU ETS is in Phase 4.

EU ETS phases are summarized as follows[8]:

Phase 1 (2005 – 2007):

- Three-year pilot (learning by doing) phase designed to prepare regulated entities, government, stakeholders and others.
- Covered only CO_2 emissions from power generators and energy-intensive industries
- Almost all allowances were given to businesses for free
- The penalty for non-compliance was €40 per tone

Phase 1 succeeded in establishing

- A price for carbon
- Free trade in emission allowance across the EU
- The infrastructure needed to monitor, report and verify emissions from businesses covered.

Emission caps for phase 1 were set on the basis of estimates since reliable emissions data was not available. This resulted in total amount of allowances issued exceeded emissions and, with supply significantly exceeding demand in 2007, the price of allowances fell to zero (phase 1 allowances could not be banked) for use in phase 2).

Phase 2 (2008 – 2012):

First commitment period which required EU countries to achieve agreed-upon national GHG emissions reduction targets.

- Lower cap on emission allowances
- Other countries joined
- The proportion of free allowances dropped to 90%
- The penalty for non-compliance was increased to €40 per tone

Phase 3 (2013 – 2020):

- Imposing of a single, EU-wide emissions cap rather than national caps.
- Auctioning is the main method of distributing allowances in the EU ETS (accounting for up to 57% of the cap)[9].

- Harmonized allocation rules applying to the allowances still given away for free.
- Inclusion of more economic sectors and GHGs
- Setting aside 300 million allowances in a New Entrants Reserve to fund deployment of innovative, renewable energy technologies and carbon capture and storage projects.

Phase 4 (current):
Tighter GHG emissions, including maritime transport, strengthening the Market Stability reserve (a reserve which functions to reduce the surplus of allowances in circulation and increase effectiveness of the EU ETS).

The EU ETS applies an emission cap that currently declines on a 2.2% linear basis over time, and mandates electricity generators cover their CO_2 emissions with an equal number of emissions allowances over a defined period commitment period.

Some of the strategies considered to reduce SO_2 emissions include, among others, coal quality improvement and the integration of renewable energy sources at coal-fired power stations.

Coal quality improvement

Efforts to improve coal quality have traditionally focused on boosting the thermal efficiency of coal-fired power stations and enhancing overall profitability. Washing coal helps lower its sulphur and ash content, which in turn reduces emissions, decreases auxiliary power consumption, and provides several additional benefits. According to National Association of Clean Air Agencies (NACAA), studies conducted in the United States show that coal washing can cut sulphur content by 10 - 20 percent. As a result, assuming at least a 10 percent reduction in SO_2 emissions from coal washing is considered a conservative estimate of its potential environmental gains (USA figures).

Supplement coal-fired generation with onsite renewable generation

There is limited information on how coal-fired power can be supported with onsite renewable energy, but at least one proven case exists. At the Xcel Energy Cameo plant in Colorado in the United States, concentrated solar power (CSP) technology was installed to supply additional heat to the plant's coal-fired heat exchanger to improve their thermal efficiency and reduce pollutant emissions.

8. Study Results

The figures below present the outcomes of the simulations conducted, covering a five-year period from FY2027 to FY2031. These results compare several modelled scenarios:

- Base: Represents the baseline case.
- SO_2_DSP_Priority Areas_2: Scenario with two separate priority areas.
- SO_2_DSP_Combined_PA_3: Scenario with a single national priority area.
- SO_2_DSP_5000_4: Scenario incorporating additional SO_2 emission cost.
- SO_2_Combined_PA_3_OBJ_W0.5: Multi-objective modelling with a weight of 0.5.
- SO_2_Combined_PA_3_OBJ_W0.8: Multi-objective modelling with a weight of 0.8.

Figure **9** below shows the coal generation over the 5-year period for all the modelled scenarios. All scenarios produce virtually identical coal generation in each year, differences are at most 1 TWh (FY2029 and FY2030). The trajectory is a monotonic decline of ~28 TWh from FY2027 to FY2031 (~17% reduction).

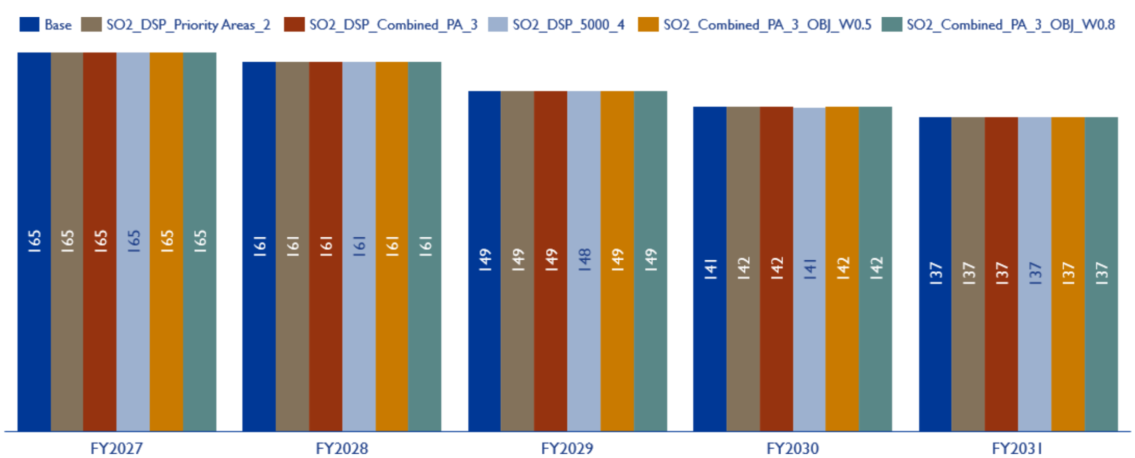


Figure 9: Coal Generation [TWh].

8.1 Base Case

The coal burn is projected to decrease from 99 231 kT in FY2027 to 82 696 kT in FY2031 which is a 17% decline (Figure 10). The year-on-year decline ranges between 3% to 7% with a significant drop from FY2028 to FY2029 (7%). This highlights the energy mix evolving, more renewable integration and shutting down of coal fired stations. At the same time, the energy forecast is also declining.

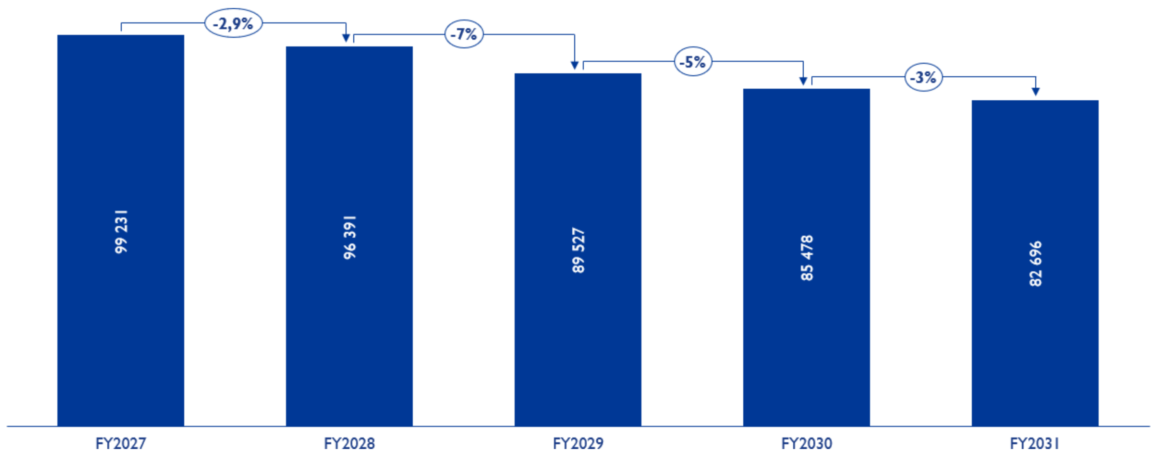


Figure 10: Base case Coal burnt [kT].

Figure **11** illustrates the SO_2 production from FY2027 to FY 2031. SO_2 emissions show a consistent downward trend from FY2027 to FY2031, achieving an overall reduction of 14.6%. Starting at approximately 1605 kT in FY2027, emissions decline gradually to around 1553 kT in FY2028 and then drop more sharply to 1466 kT by FY2029, marking the most significant year-on-year decline. The reduction continues steadily through FY2030, reaching about 1405 kT, and stabilizes near 1371 kT in FY2031. This indicates that a decline in coal burn will also have a direct positive impact on SO_2 emission reduction.

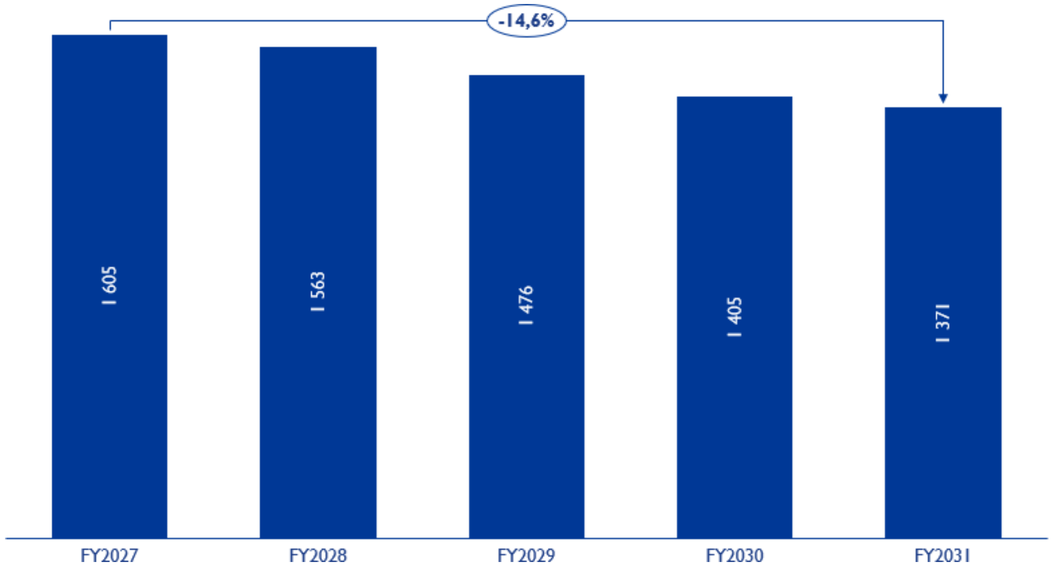


Figure 11: Base case SO_2 production [kT].

The average annual SMP is projected to drop from R188/MWh in FY2027 to R177/MWh in FY2031 (Figure 12). The dip in FY2029 and FY2030 is due to adequate capacity to meet demand. The SMP is expected to slightly increase in FY2031 due to shutdown of the five coal fired stations by FY2030. In the Base Case, no additional emission cost was assigned to the power stations. Therefore, no emission cost was reported.

Figure 12: Base case System Marginal Price (SMP) [R/MWh]

8.2 Option 1: SO_2 Dispatch Prioritization Strategy Priority Areas_2

Applying the SO_2 cost per PA resulted in coal burn decrease from 99 163 kT in FY2027 to 82 626 kT in FY2031 which is a 17% decline (Figure 13). The decline from the Base case is 0.1% over the study period. This shows a very small reduction in the coal burn between the two study cases.

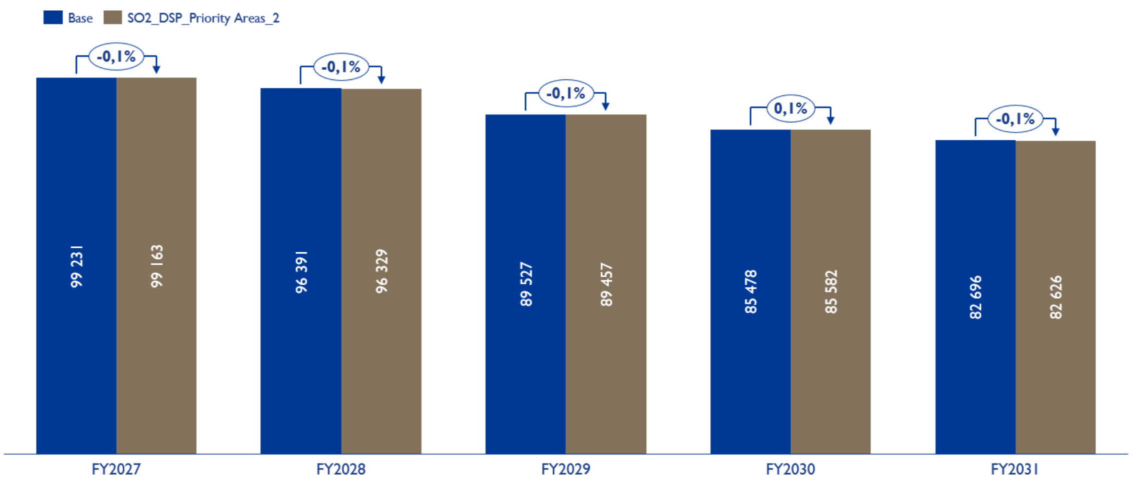


Figure 13: Option 1 Coal burnt [kT].

Figure 14 illustrates the SO_2 production from FY2027 to FY2031. A steady decline of SO_2 emissions production can be seen starting at 1595 kT in FY2027 ending at 1361 kT by FY2031 indicating a 14.7% decline which is 0.1% improvement compared to the base case scenario. The year-on-year difference between the two scenarios ranges from 0.5% to 0.7%.

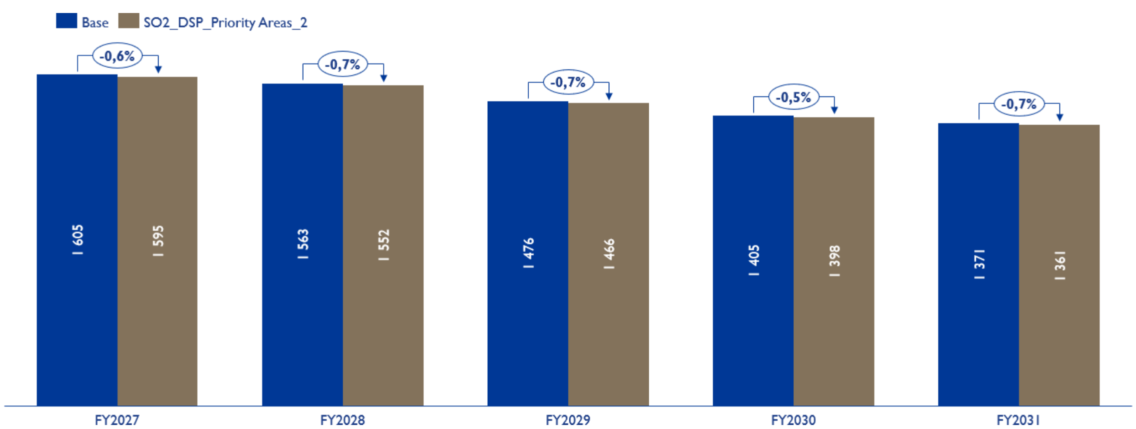


Figure 14: Option 1 SO_2 production [kT].

The annual average SMP is projected to drop from R201/MWh in FY2027 to R189/MWh in FY2031 (Figure 15). The dip in FY2029 and FY2030 is due to adequate capacity to meet demand. The SMP is expected to slightly increase in FY2031 due to shutdown of the five coal fired stations by FY2030. Adding emission cost per priority areas increases the annual average SMP by 7.1% from R188/MWh to R201/MWh in FY2027. However, the reduction in SO_2 emissions is only 0.6% for FY2027. This outcome is expected throughout the planning horizon up to FY2031. The increase in annual average SMP increases the total system cost with minimal benefit in SO_2 emission reduction. The total SO_2 cost for FY2027 is expected to be around R1.5 billion and expected to decline to about R1.2 billion in FY2031 due to the drop in SO_2 emissions as shown in the Appendix (Figure 32).

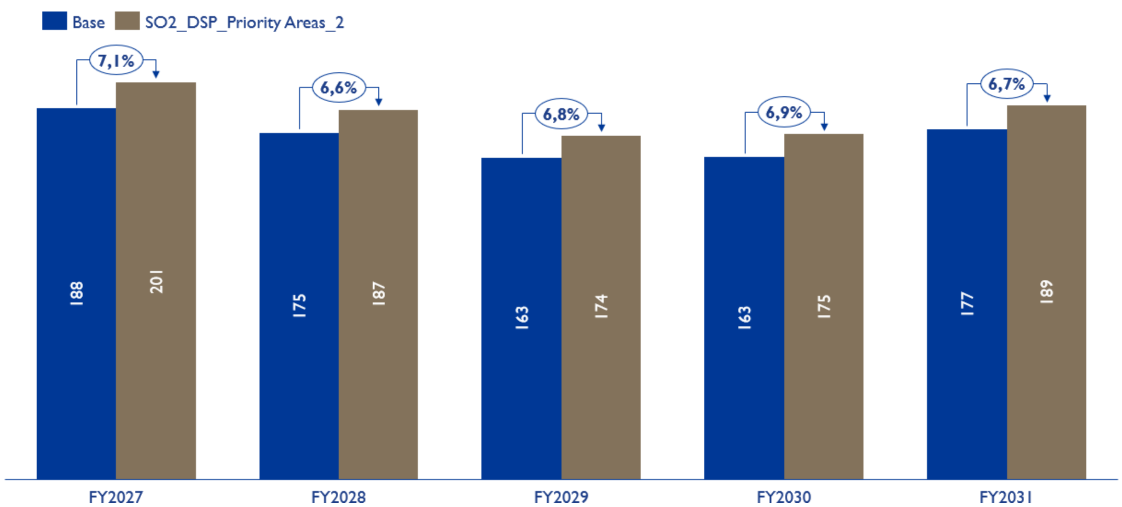


Figure 15: Option 1 System Marginal Price (SMP) [R/MWh]

Waterberg PA

In the Waterberg Priority Area, coal generation remains stable over the study period, decreasing only slightly from about 53 TWh in FY2027 to approximately 51 TWh in FY2031 which is about 4% reduction (Figure **16**).

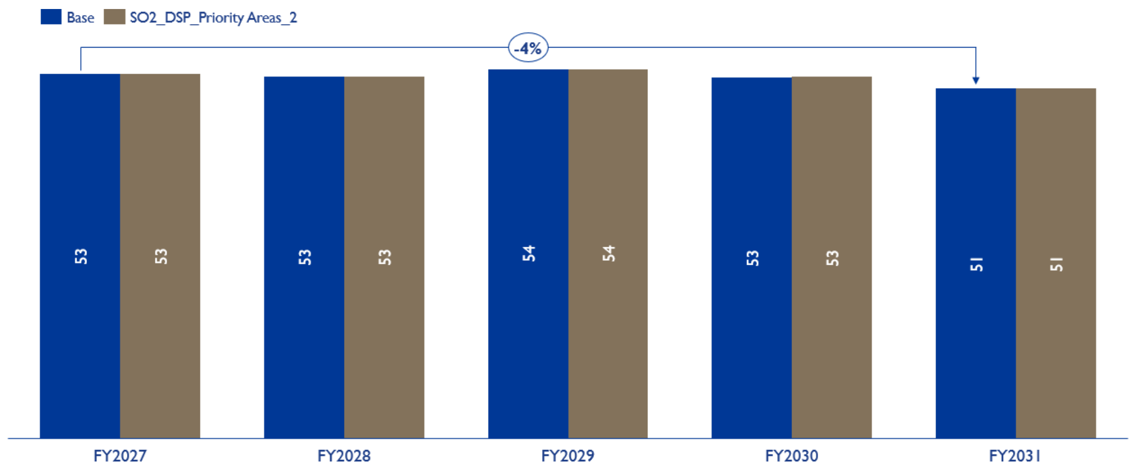


Figure 16: Waterberg PA Coal Generation [TWh].

The coal burn is projected to decrease from 29 535 kT in FY2027 to 28528 kT in FY2031 which is a 3% decline as indicated in (Figure 17). The year-on-year decline ranges up to 0.2%. There is an overall minimal difference from the Base case suggesting that this option has no impact on SO_2 reduction.

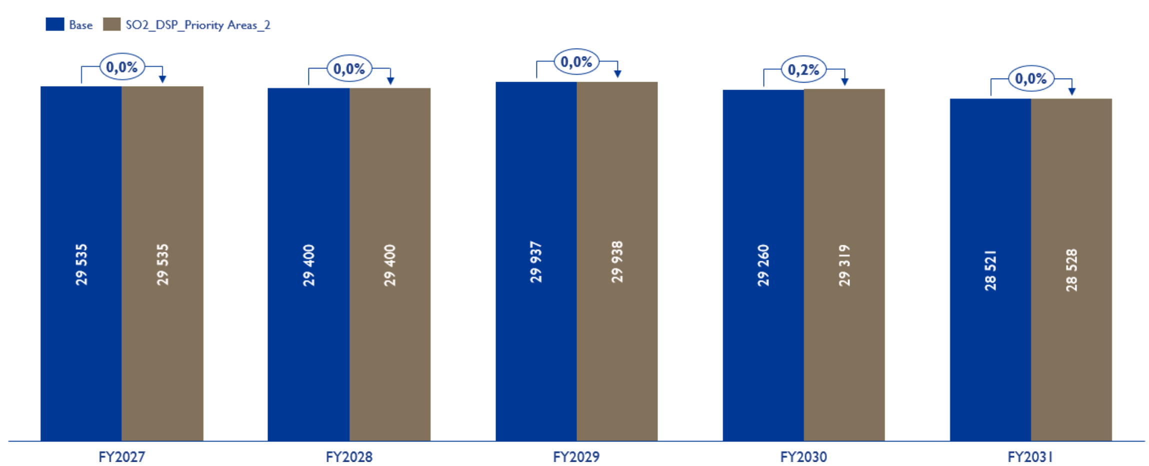


Figure 17: Waterberg PA Coal Burn [kT]

The SO_2 emissions show a modest decline, moving from around 602 kT in FY2027 to 584 kT by FY2031, representing about a 3% reduction from the base case (Figure **18**). This limited change suggests that Waterberg Priority Area coal fired power stations maintained consistent utilization during the study period.

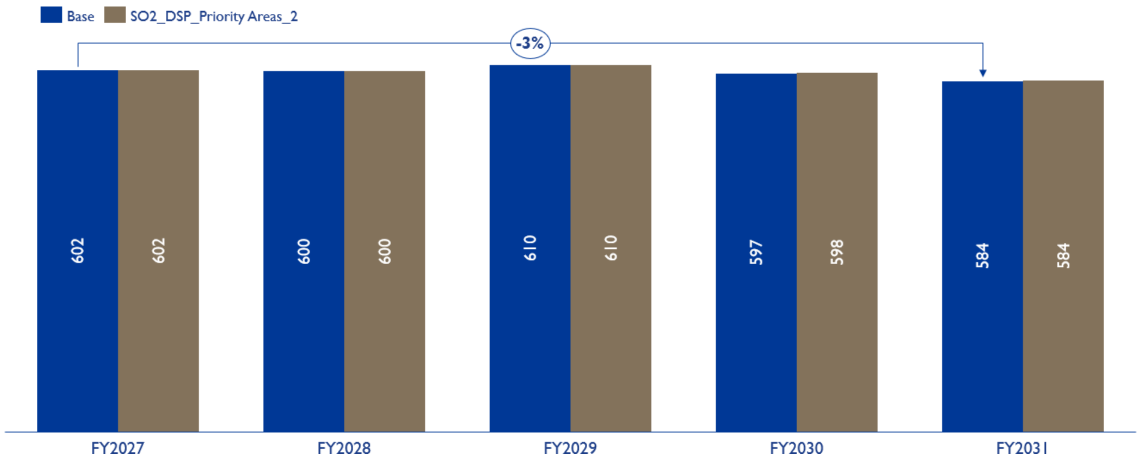


Figure 18: Waterberg PA SO_2 Production [k Tonne]

Highveld PA

In the Highveld Priority Area, coal generation declines significantly over the study period, dropping from approximately 112 TWh in FY2027 to about 86 TWh in FY2031 which translates to 23% (Figure 19). The energy production remains the same for both the base case and this option.

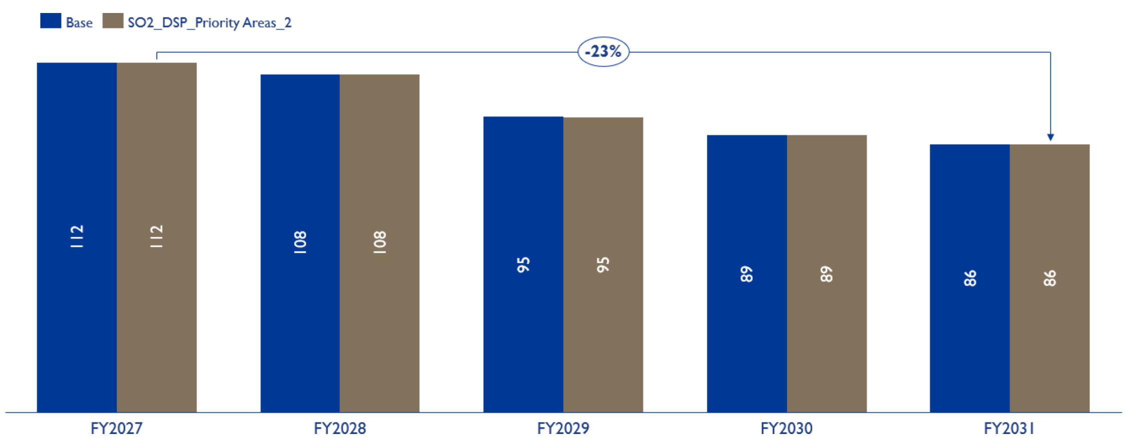


Figure 19: Highveld PA Coal Generation [TWh]

The coal burn is projected to decrease from 69 628 kT in FY2027 to 54 098 kT in FY2031 which is a 22% decline as indicated in (Figure 20). The difference between the Base case and this option is 0.1% each year throughout the study period.

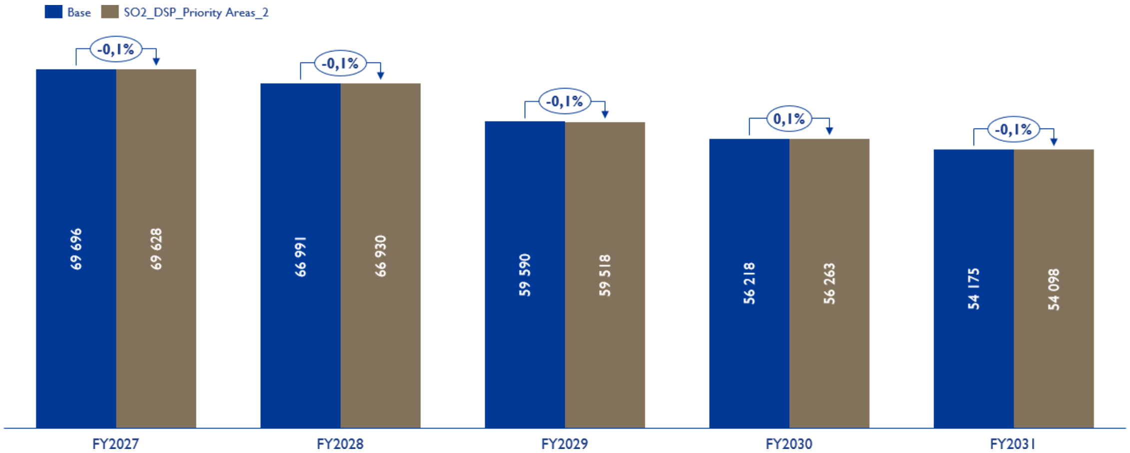


Figure 20: Highveld PA Coal Burn [kT]

SO_2 production decreases from around 1,033 kT in FY2027 to 777 kT by FY2031, representing a 21.8% reduction (Figure 21). This reduction is attributed to a declining forecast, integration of renewables and also the shutdown of five power station in the Highveld PA.

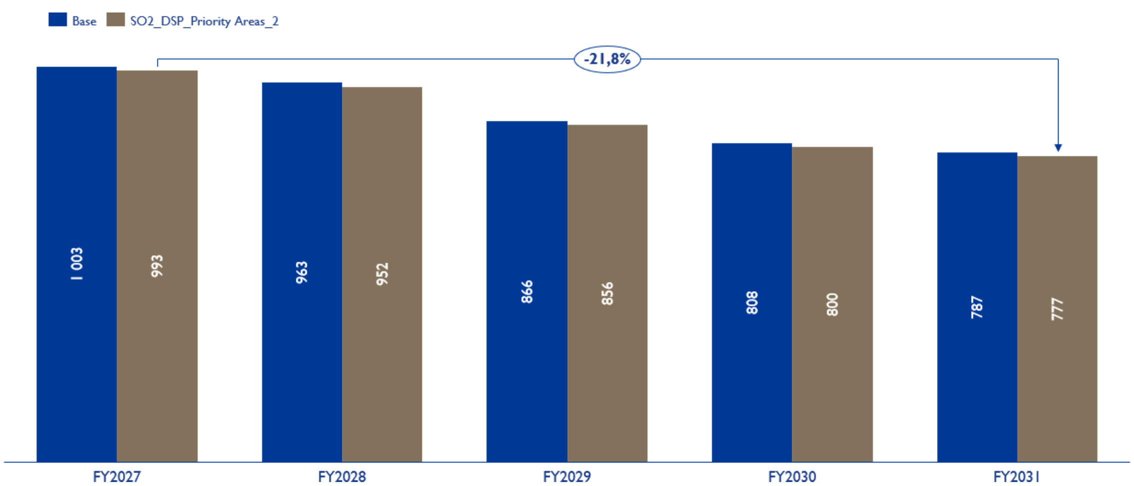


Figure 21: Highveld PA SO_2 Production [k Tonne]

8.3 Option 2: SO_2 Dispatch Prioritization Strategy Combined Priority Areas

Combining the priority areas into one, resulted in coal burn decrease from 99 162 kT in FY2027 to 82 632 kT in FY2031 which is a 17% decline (Figure 22). The year-on-year variance between the Base case and the this option remains minimal at approximately ±0.1% over the study period. The most pronounced decrease occurs between FY2028 and FY2029 at a value of 7% followed by 4% from FY2029 to FY2030.

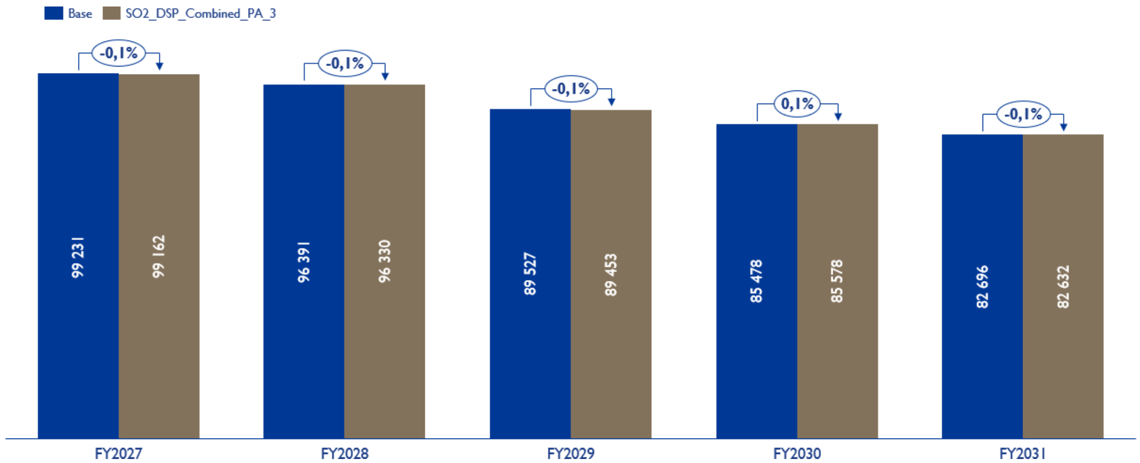


Figure 22: Option 2 Coal burnt [kT].

The SO_2 emissions production decrease from 1595 kT in FY2027 to 1360 kT in FY2031, achieving an overall reduction of 14.7%. Emissions begin at 1595 kT in FY2027 and decrease slightly to 1552 kT in FY2028. A more significant drop occurs in FY2029, where emissions fall to 1466 kT, marking the most impactful year-on-year improvement. The decline continues through FY2030, reaching 1397 kT, and stabilizes at 1360 kT by FY2031. This option follows the same trend as the option 1 priority areas since Waterberg coal fired stations remain in the top three cheapest stations in merit order. Therefore, minimal change is expected in the overall outcome.

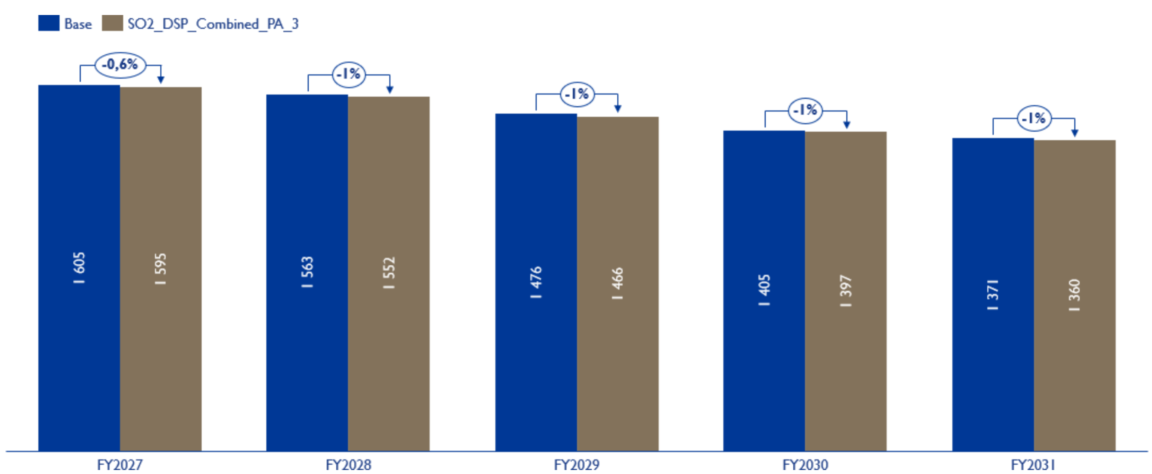


Figure 23: Option 2 SO_2 production [kT].

The annual average SMP is projected to drop from R201/MWh in FY2027 to R189/MWh in FY2031. The dip in FY2029 and FY2030 is due to adequate capacity to meet demand. The SMP is expected to slightly increase in FY2031 due to shutdown of the five coal fired stations by FY2030.

Combining the emission cost for the priority areas, increases the annual average SMP by 7% from R188/MWh to R201/MWh in FY2027. However, the reduction in SO_2 emissions is only 0.6% for FY2027. This outcome is expected throughout the planning horizon up to FY2031. The increase in annual average SMP increases the total system cost with minimal benefit in SO_2 emission reduction. The total SO_2 cost for FY2027 is expected to be around R2.5 billion and expected to decline to about R2.1 billion in FY2031 due to the drop in SO_2 emissions. This increase in SO_2 cost is driven by Medupi and Matimba SO_2 emission cost that increases from R54 per ton (Option 1 Priority Area) to R1 574 per ton in the combined priority area. However, this has a minimal impact on SO_2 overall emissions since these power stations produced relatively the same throughout this option.

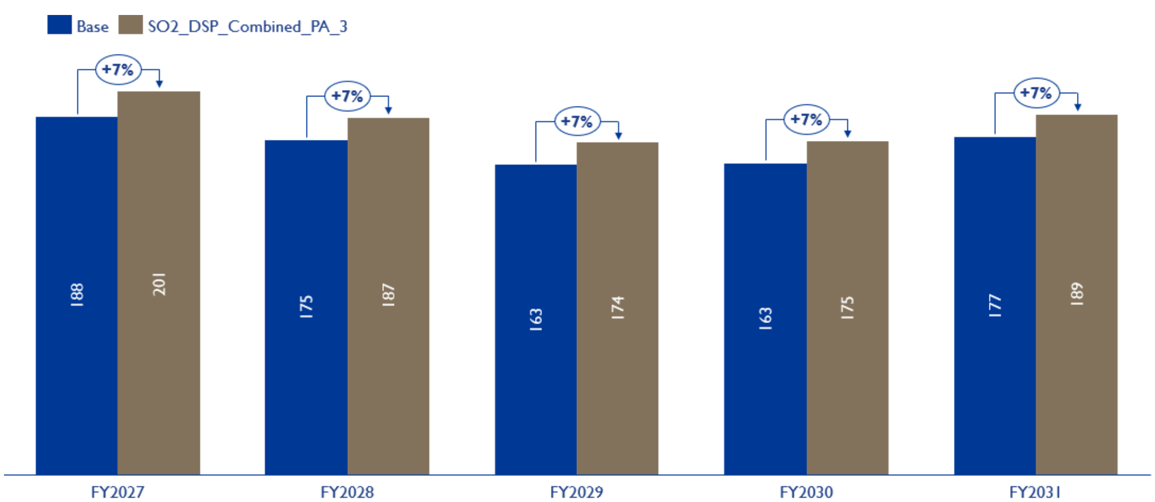


Figure 24: Option 2 System Marginal Price (SMP) [R/MWh]

8.4 Option 3: SO_2 Dispatch Prioritization Strategy Additional Cost

Applying an additional SO_2 emission cost on the combined priority area resulted in coal burn decrease from 98 914 kT in FY2027 to 82 6087 kT in FY2031 which is a

17% decline (Figure 25). The year-on-year variance between the Base case and this option ranges between 0.3% to 0.7% over the study period.

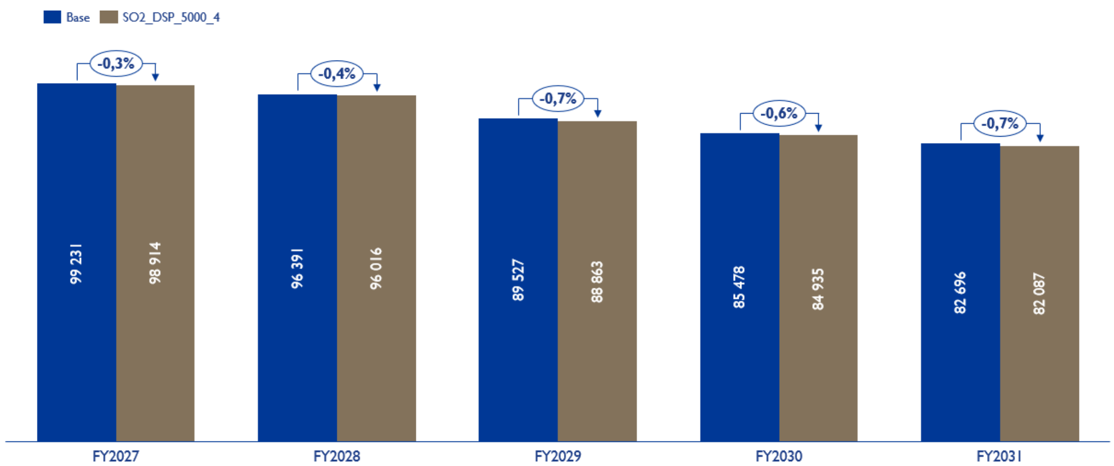


Figure 25: Option 3 Coal burnt [kT].

SO_2 emissions production follows a downward trend starting from 1538 kT in FY2027 to 1289 kT in FY2031, achieving the largest overall reduction among the scenarios at 16.2% (Figure 26). In comparison with the base case, SO_2 emissions drop by 4.2% in FY2027 and by 6.0% in FY2031. This is the highest reduction achieved across all scenarios. The year-on-year variance between the Base case and this option ranges between 4.2% to 6.6% over the study period. The highest reduction is observed in FY2029.

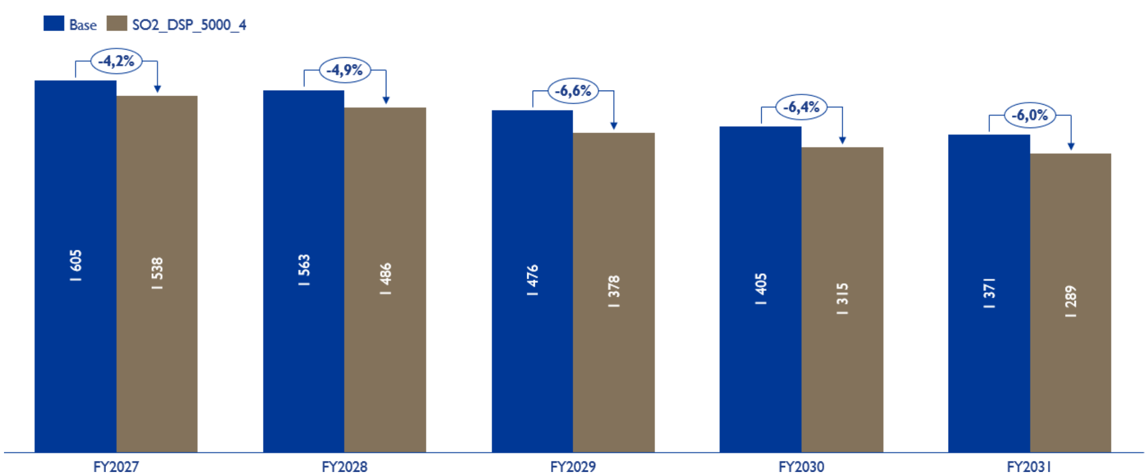


Figure 26: Option 3 SO_2 production [kT].

The annual average SMP is projected to slightly drop from R246/MWh in FY2027 to R231/MWh in FY2031. The dip in FY2029 and FY2030 is due to adequate capacity to meet demand (Figure 27). The SMP is expected to slightly increase in FY2031 due to shutdown of the four coal fired stations by FY2030. Adding emission cost per combined priority areas increases the annual average SMP by 30.9% from R188/MWh to R246/MWh in FY2027. However, the reduction in SO_2 emissions is only 4.2% for FY2027. This outcome is expected throughout the planning horizon up to FY2031. The increase in annual average SMP increases the total system cost with minimal benefit in SO_2 emission reduction. The total SO_2 cost for FY2027 is expected to substantially increase to be around R10.1 billion and expected to decline to about R8.5 billion in FY2031 due to the drop in SO_2 emissions. This increase in SO_2 cost is driven by additional SO_2 emission cost that increases from R1 574 per ton (Option 2 Combined Priority Area) to R6 574 per ton in the combined priority area with additional cost. The overall SO_2 cost incurred over the five years accumulates to R46.1 billion.

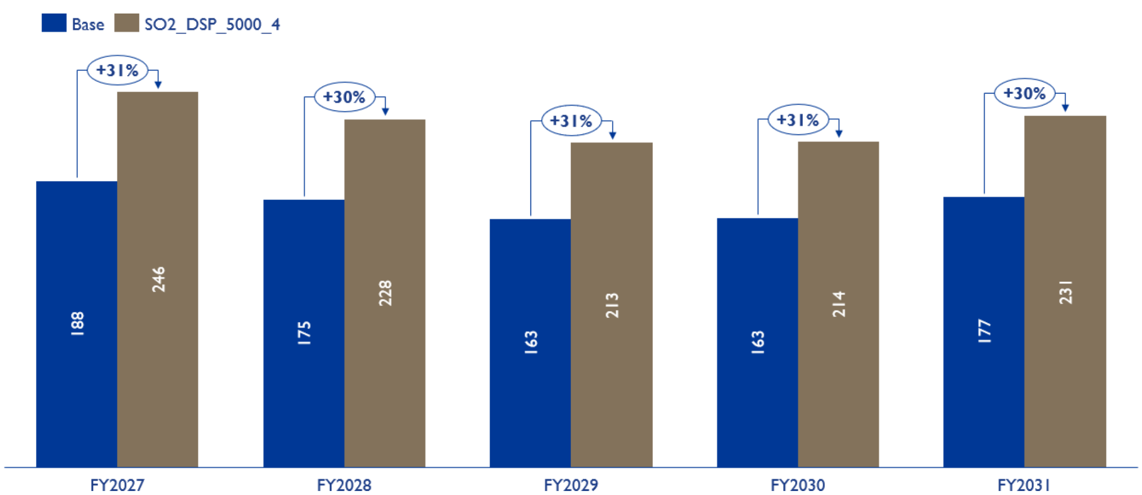


Figure 27: Option 3 System Marginal Price (SMP) [R/MWh]

8.5 Option 4: Multi-Objective Modelling

SO_2_Combined_PA_3_OBJ_W0.5:

Applying a multi-objective approach with a weighting of 0.5 resulted in coal burn decrease from 99 196 kT in FY2027 to 82 658 kT in FY2031 which is a 14.6%

decline (Figure 28). The year-on-year variance between the Base case and the this option ranges between 0.04 % to 0.16% over the study period.

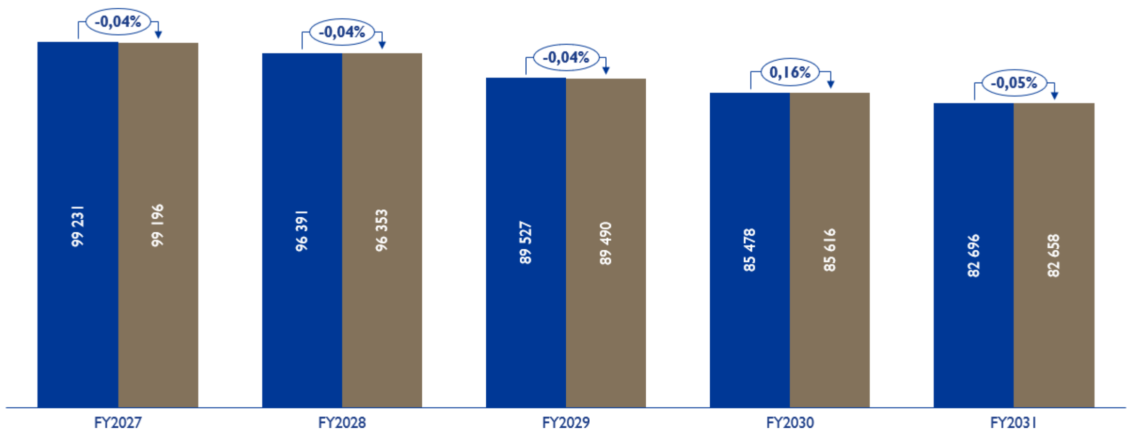


Figure 28: Option 4 W0.5 Coal burnt [kT].

There's a minimal decline in SO_2 emissions from 1601 kT in FY2027 to 1368 kT in FY2031, achieving an overall reduction of 14.6% (Figure 29). In comparison with the base case, SO_2 emissions drop by 0.2% in FY2027. The year-on-year variance between the Base case and this option ranges between 0% to 0.3% over the study period.

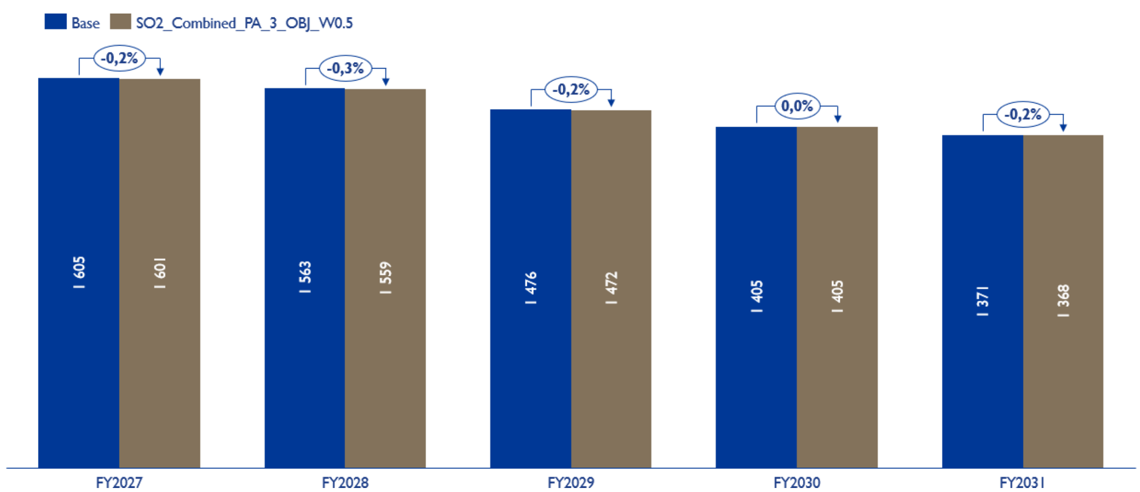


Figure 29: Option 4 W0.5 SO_2 production [kT].

SO_2_Combined_PA_3_OBJ_W0.8:

Applying a multi-objective approach with a weighting of 0.8 resulted in coal burn decrease from 99 179 kT in FY2027 to 82 634 kT in FY2031 which is a 16.7% decline (Figure 30). The year-on-year variance between the Base case and this option ranges between 0.05 % to 0.13% over the study period.

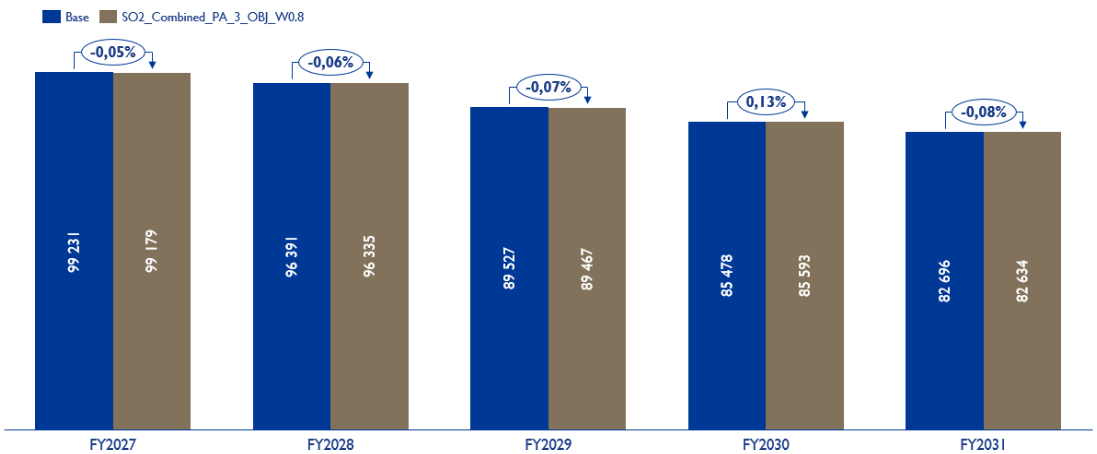


Figure 30: Option 4 W0.8 Coal burnt [kT].

There's a minimal decline in SO_2 emissions production from 1597 kT in FY2027 to 1364 kT FY2031, achieving an overall reduction of 14.6% (Figure 29). In comparison with the base case, SO_2 emissions drop by 0.4% in FY2027. The year-on-year variance between the Base case and this option ranges between 0.3% to 0.6% over the study period.

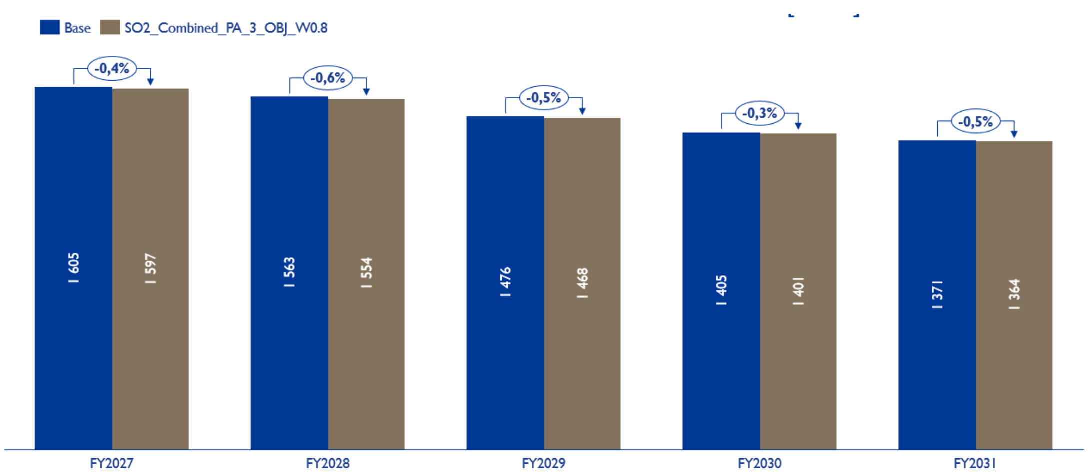


Figure 31: Option 4 W0.8 SO_2 production [kT].

9. Conclusion

Electricity system adequacy is maintained in all scenarios from FY2027 to FY2031. SO_2 emissions are declining due to the evolving energy mix (notably the introduction of renewables), power station retirement (approximately 8GW) and a forecasted reduction in overall energy demand. Specifically, overall SO_2 emissions are expected to decrease from 1605 kT in FY2027 to 1371 kT in FY2031, representing a 14.6% reduction in the base case scenario.

In the base case, Waterberg PA emissions are anticipated to drop modestly from 602 kT to 584 kT which is a 3% decrease. In contrast, Highveld PA is expected to see a more substantial reduction, with emissions falling from 1003 kT to 787 kT, amounting to a 22% decrease over the five-year period. With the decommissioning of Arnot, Camden, Grootvlei, Hendrina and Kriel, there is a slight ramp up in SO_2 production at Kendal, Lethabo, and Tutuka power stations in FY2031.

Applying SO_2 emission charges, whether by priority area or as a combined area charge, has only a minimal impact on reducing overall SO_2 emissions. For example, in FY2027, implementing a priority area emission charge results in SO_2 emissions decreasing from 1605 kT to 1595 kT compared to the Base case, which equates to just a 0.6% reduction. However, this modest improvement in emissions comes at a notable economic cost, as the annual average System Marginal Price (SMP) is projected to increase by 7%, rising from R188/MWh to R201/MWh. This demonstrates that while emission charges can influence dispatch decisions, their effectiveness in significantly reducing SO_2 emissions is limited unless set at much higher levels, which would further escalate energy prices.

A substantial reduction in SO_2 emissions requires the implementation of a significantly higher emission charge. For example, applying a charge of R6 575 per ton results in a 4.2% decrease in SO_2 emissions, lowering them from 1605 kT to 1538 kT in FY2027. However, this more pronounced environmental benefit comes at a considerable economic cost, as the annual average System Marginal

Price (SMP) rises sharply by 31%, from R188/MWh to R246/MWh. This substantial increase in the energy market price highlights the trade-off between achieving meaningful emissions reductions and maintaining affordable electricity prices. In this scenario, emission reductions are primarily observed at Kendal, Majuba, Matla, and Tutuka power stations, due to their repositioning in the merit order. Conversely, stations such as Duvha, Kriel, Arnot, and Kusile increase their production under this scenario. Despite these shifts, high-emitting stations like Lethabo, Matimba, and Medupi consistently remain at the top of the merit order across all scenarios, resulting in their emissions staying relatively unchanged. This dynamic means that, in the Waterberg PA, SO_2 emissions remain stable because Matimba and Medupi do not reduce their output.

In contrast, the Highveld PA experiences a decline in SO_2 emissions, driven by station shutdowns and a trade-off where some stations increase production while others decrease in response to the high SO_2 cost. Overall, the imposition of an SO_2 emission charge has only a minimal effect on the broader goal of reducing total SO_2 emissions, while simultaneously increasing costs for generators and raising the SMP. Multi-objective optimization approaches have not yielded significant improvements over the base case, suggesting that a cap-and-trade system may be more effective in achieving meaningful SO_2 emission reductions without incurring high costs.

10. Recommendations

While SO_2 emissions are projected to decline by 14.6% in the base case from FY2027 to FY2031, any further reductions require structural interventions rather than incremental pricing adjustments. A combination of accelerated renewables, plant retirements, targeted abatement technologies, and market-based mechanisms such as cap-and-trade will be essential to achieve compliance and minimize health and environmental impacts without compromising affordability. The results indicate that SO_2 emission charge can be implemented, however, there will be minimal impact in the overall objective of reducing SO_2 emission. The emission charge will have to be extremely large to achieve a significant SO_2 reduction.

Further, Medupi and Matimba have relatively low CO_2 production per MWH of energy generated. Any optimization for SO_2 which reduces production from these stations will also therefore need to be considered in terms of the impact this would have on total CO_2 production as more CO_2 emitting stations may be required to meet the demand displaced from high SO_2 emitting stations.

Provided that SO_2 emissions are already projected to significantly drop without implementing the emission charge, implementing the emission charge will be counterproductive. If considered necessary a lternative options such as cap-and-trade could be considered to further reduce SO_2 emissions without incurring significant costs to Eskom generators, thus increasing the energy prices for consumers and assuming CO_2 constraints can be managed.

The cap-and-trade system has produced positive results in emission reduction in the United States as well as European Union[10]. The cap-and-trade becomes the secondary market governed by an established body or it can be incorporated into the existing market structures. It will provide much greater flexibility to achieve any given emission standard since generators which face high marginal abatement costs may purchase SO_2 permits from other generators which face lower marginal abatement costs. The revenue generated through the cap-and-trade mechanism is allocated to programmes and initiatives designed to achieve SO_2 emission reductions.

If cap-and-trade is required, it can be introduced in phases during the energy market transition as well as in full competitive energy markets.

Phase 1:

a) This will be a pilot phase designed to prepare entities and stakeholders.
b) Establish the structures to govern the cap-and-trade market.
c) Develop the rules and regulations to manage the cap-and-trade market.
d) Establish the infrastructure required to monitor, report and verify emissions from generators i.e trading platforms.
e) Set a national emission cap based on historical emission data.
f) Free allocation of emission allowances to the generators based on historical emission data.
g) Establish or set a penalty for non-compliance to the emissions allowances.

Phase 2:

a) Impose a single national emission cap with a declining trend from phase 1.
b) Start auctioning allowances to generators.
c) Increase the penalty for non-compliance.
d) Investigate the effectiveness of emissions capping against the emissions objective. The emission cap will have to decline over time to enforce the overall objective.

Phase 3:

Based on the outcome of phase 2 assessments:

a) Regional emission caps may need to be implemented especially for priority areas where minimal emission reductions are achieved.
b) Strengthening the rules and regulations where necessary.
c) Include other economic sectors which contributes to SO_2 emissions.

Phase 4:

a) Implement tighter emissions caps.
b) Continuous monitoring.

At this stage, no recommendations are made in terms of the starting cap allowance. This will be dictated by the implementation of cap-and-trade system and starting period. Actual SO_2 emission will have to be used as the basis of setting the starting point of the cap allowance and set the acceptable declining trend over time in a way that does not negatively impact on the national electricity supply or any CO_2 constraints.

11. References

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12. Appendices

The figure below illustrates the projected SO_2 costs across the different options investigated together with study results for the options investigated.

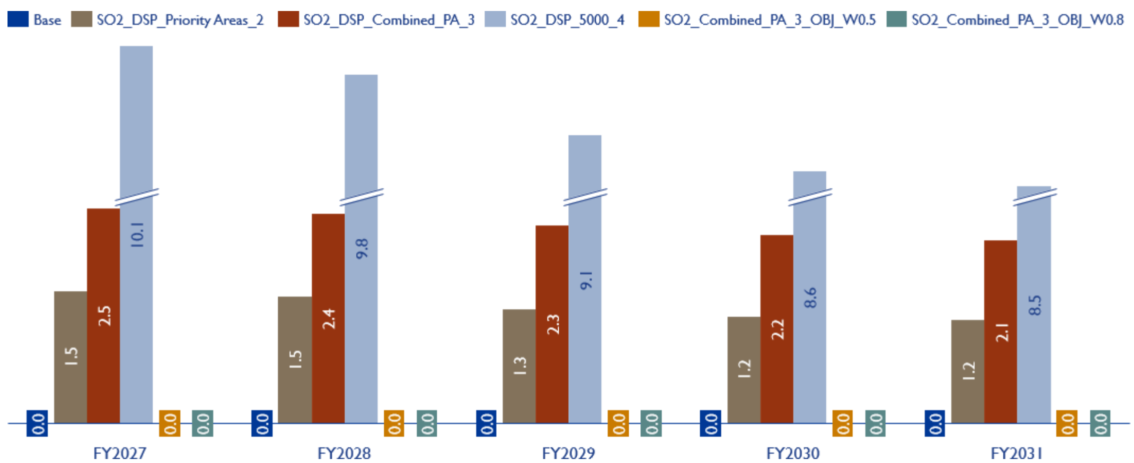

Figure 32: SO_2 Cost [R'm].

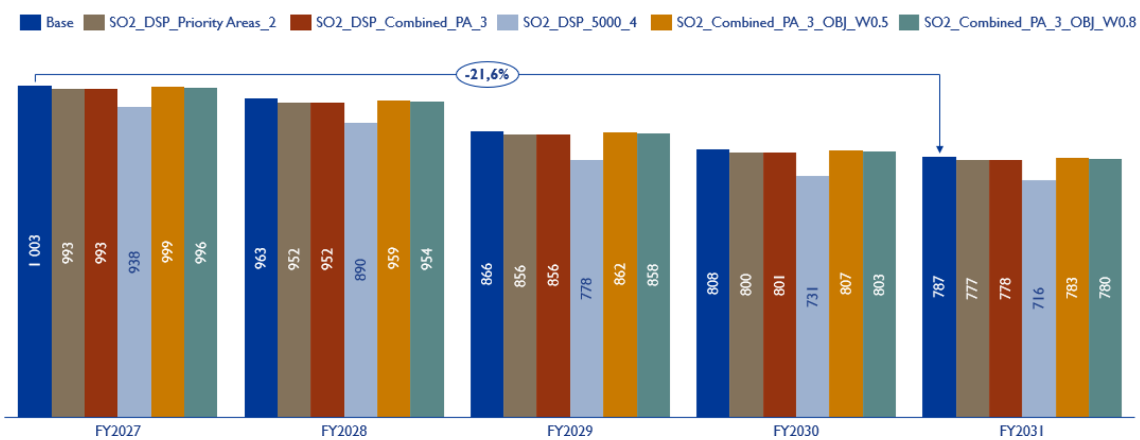

Figure 33: Highveld PA Coal Generation [TWh].

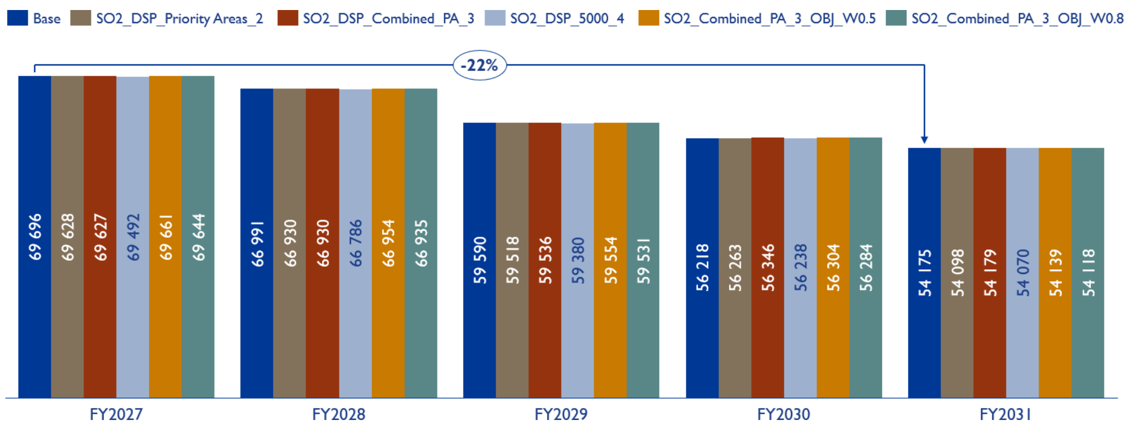

Figure 34: Highveld PA Coal burnt [kT].

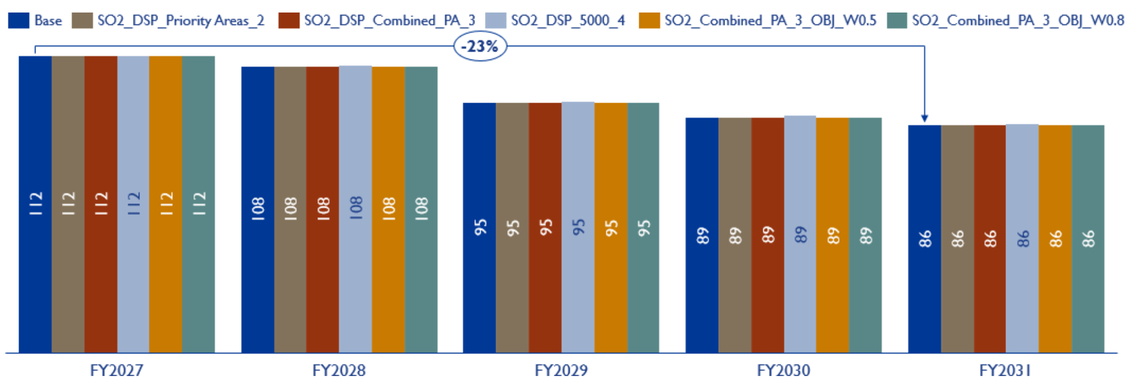

Figure 35: Highveld PA SO_2 Production [kT]

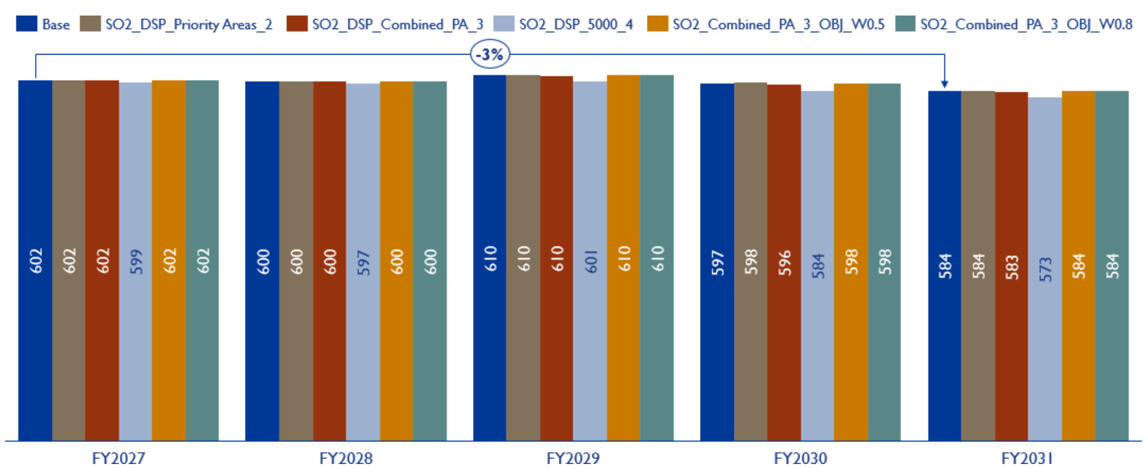

Figure 36: Waterberg PA SO_2 Production [kT].

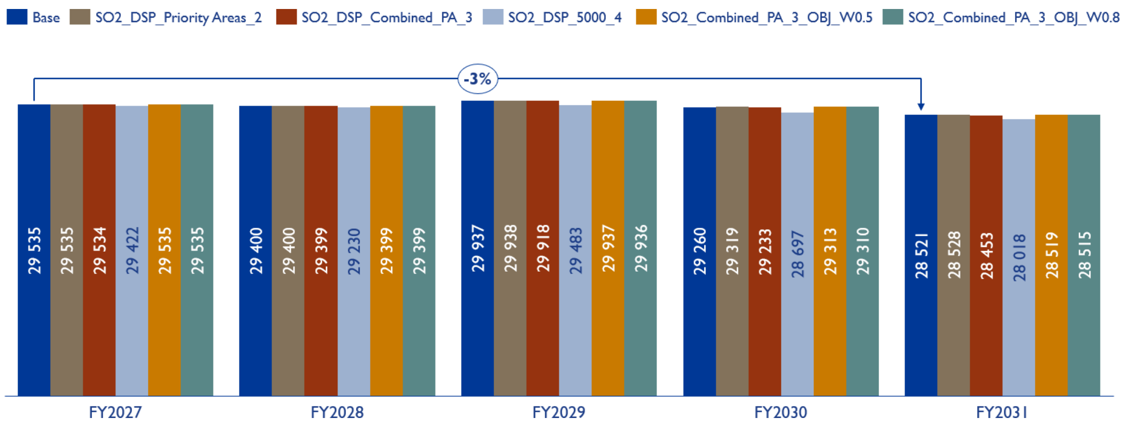

Figure 37: Waterberg PA Coal burnt [kT].

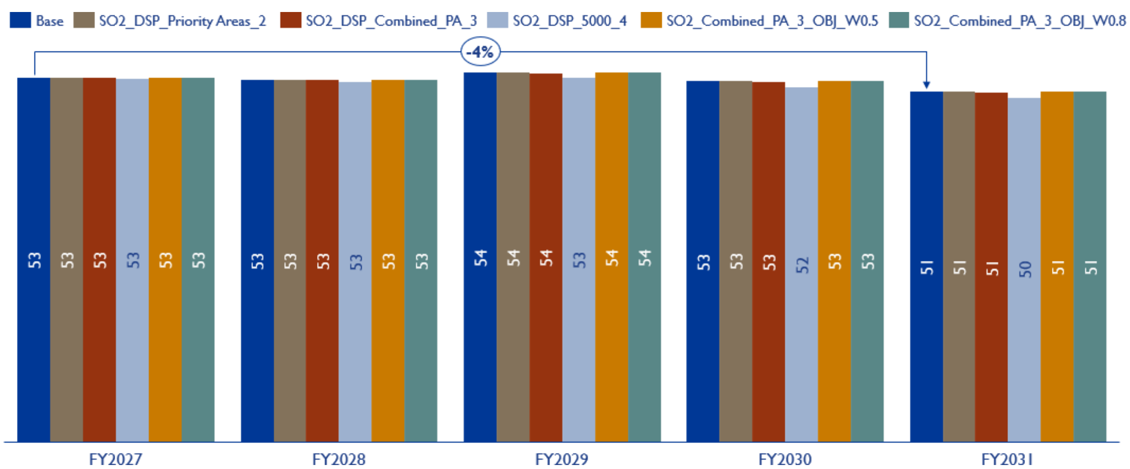

Figure 38: Waterberg PA Coal Generation [TWh].

SO_2 emissions for Arnot, Camden, and Grootvlei decline steadily from FY2027 through FY2030 before reaching zero in FY2031, reflecting planned shutdown and consequently removing their SO_2 footprint (Figure **39**). In contrast, Duvha remains a significant emitter throughout the study period.

Arnot's SO_2 emissions start at approximately 12.5 kT in FY2027, remaining stable during these years. A moderate decline occurs in FY2029, with emissions dropping to around 11.5 kT. By FY2030, emissions fall sharply to about 9.8 kT, and by FY2031, they reach zero across all scenarios, reflecting complete station retirement. Camden's SO_2 emissions remain steady at approximately 12.5 kT during FY2027, followed by a moderate decline to around 11.6 kT in FY2028 and 11.5 kT in FY2029. A sharper reduction occurs in FY2030, with emissions dropping to about 98.8 kT. By FY2031, Camden records zero emissions across all scenarios, indicating complete station retirement. Duvha SO_2 emissions starts at at 39.3 - 53.5 kT in FY2027 and decrease moderately to about 36 - to 42.9 kT in FY2031. Grootvlei SO_2 emissions remain stable at about 10.7 – 10.9 kT from FY2027 to FY2029. A significant decline occurs in FY2030, with emissions dropping to approximately 8.4 kT. By FY2031, Grootvlei achieves zero emissions across all scenarios, signalling full retirement.

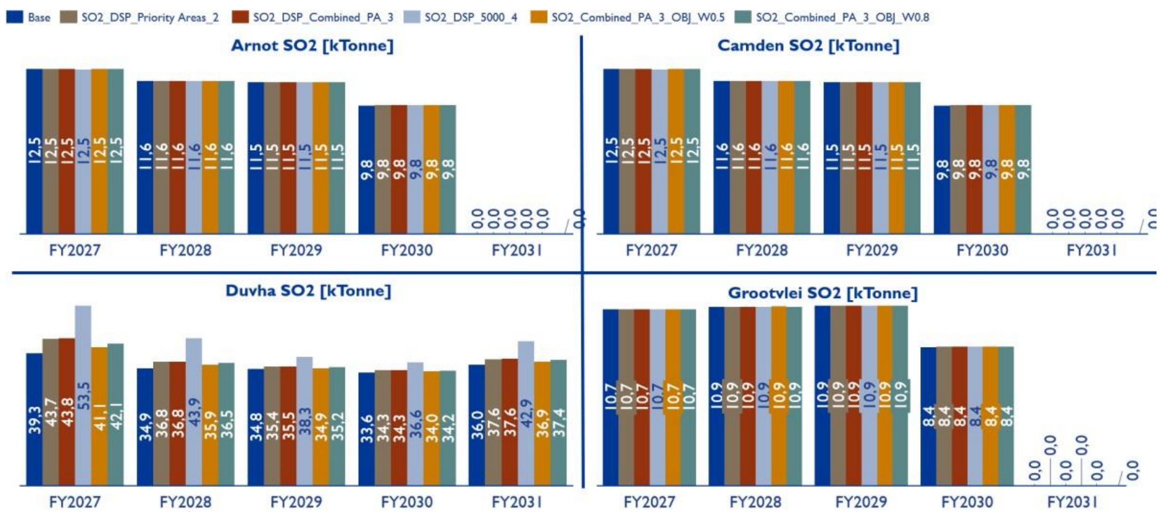

Figure 39: SO_2 emissions for Arnot, Camden, Duvha and Grootvlei power stations.

Figure **40** shows the SO_2 emissions results for Hendrina, Kendal, Kriel underground and Kriel open cast power stations. Hendrina's SO_2 emissions remain high and stable at approximately 13.8 kT for all scenarios in FY2027 and remains steady around this figure until FY2029. A sharp decline occurs in FY2030, with emissions dropping to around 6.9 and 7 kT for all scenarios. By FY2031, Hendrina records zero emissions across all scenarios, indicating complete station retirement. Kendal's SO_2 emissions display a varied pattern over the projection period, beginning at approximately 198 kT across five scenarios, while the Additional Cost scenario starts lower at about 173 kT in FY2027. Kriel Units 1–3 show a gradual decline in SO_2 emissions over the projection period, starting at 27–28 kT across five scenarios and 32 kT under the Additional Cost scenario in

FY2027. By FY2030, emissions drop noticeably to around 15.7 kT across all scenarios, followed by full station retirement in FY2031, which eliminates emissions entirely and significantly reduces the overall SO_2 footprint. Kriel Units 4–6 show a slight decline in SO_2 emissions over the projection period, starting at approximately 25 kT across five scenarios and 29 kT under the Additional Cost scenario in FY2027. Emissions decrease gradually to around 23 kT by FY2030 across all scenarios, followed by full station retirement in FY2031, which effectively eliminates emissions and significantly reduces the overall SO_2 footprint.

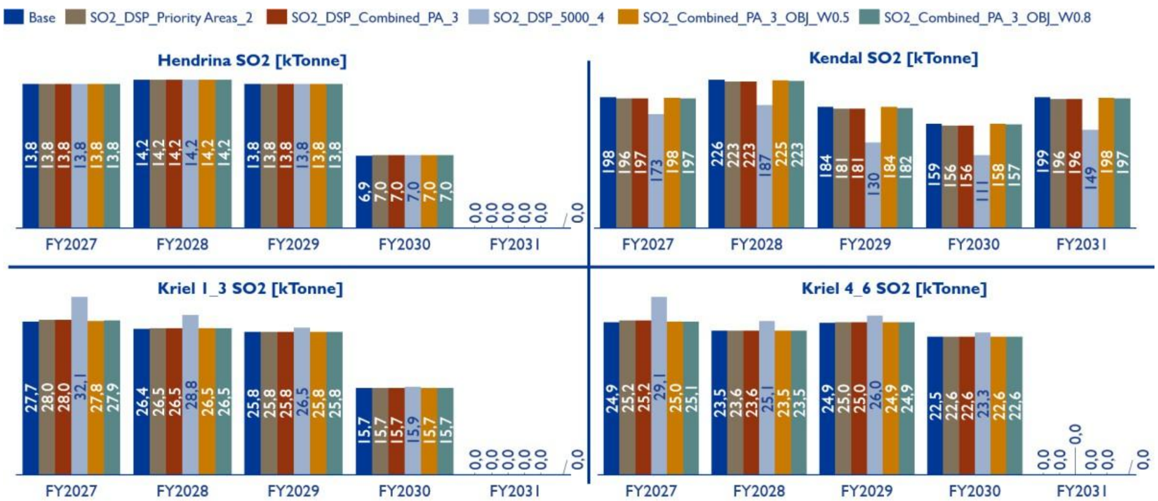

Figure 40: SO_2 emissions for Hendrina, Kendal and Kriel power stations.

Figure **41** shows the SO_2 emissions results for Kusile, Lethabo, Majuba underground and Majuba open cast power stations. Kusile's SO_2 emissions begin at approximately 60 kT in FY2027 for five scenarios and steadily decreases in FY2029 where it maintains a value of around 40 kT by FY2031. However, the *Additional* cost scenario starts at 82 kT in FY2027 with an increase to 89 kT in FY2028. In FY2029 there is a decrease to 77 kT and 72 kT by FY2031. Lethabo's SO_2 emissions remain consistently high throughout the projection period, starting at approximately 211 kT in FY2027 and fluctuating slightly between 206 and 220 kT across all scenarios through FY2031. However, there is a decrease in FY2028 to around 186 kT for all scenarios. Majuba Units 1-3 show a clear downward trend in SO_2 emissions over the projection period, starting at ranging from 51 to 69 kT for all scenarios in FY2027 and declining steadily to around 49 - 54 kT by FY2031. Majuba Units 4-6 exhibit higher emissions compared to Majuba units 1-3 and show an overall downward trend in SO_2 emissions over the projection period, starting at ranging from 58 to 80 kT for all scenarios in FY2027 and declining steadily to around 53 – 60.

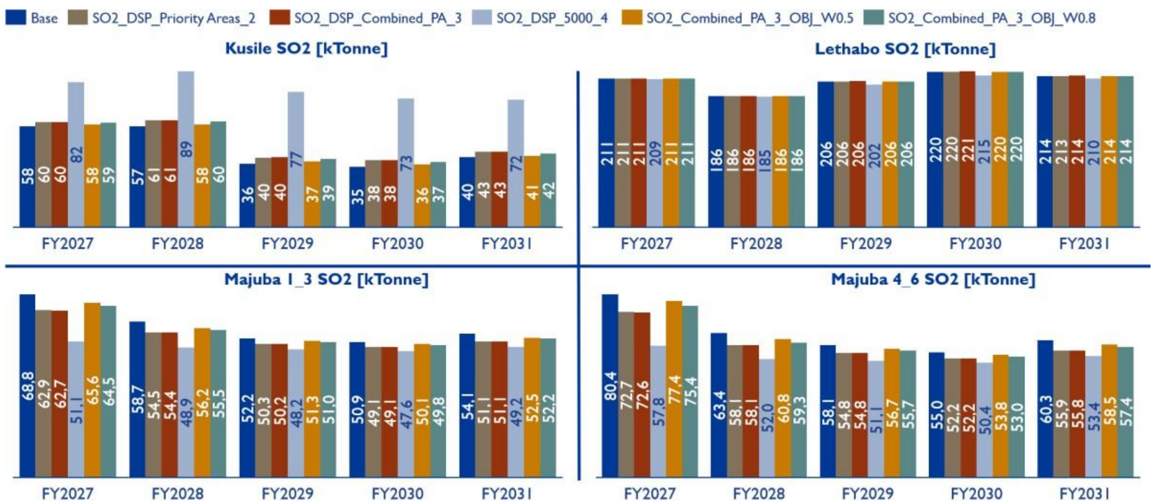

Figure 41: SO_2 emissions for Kusile, Lethabo and Majuba power stations.

Figure 42 shows the SO_2 emissions results for Matimba, Matla, Medupi and Tutuka. For Matimba, SO_2 emissions remain stable across FY2027–FY2031, fluctuating only slightly between 348 kT and 355 kT depending on the scenario. The base case starts at 348 kT in FY2027 and rises marginally to 355 kT in FY2029 before tapering back to 350 kT by FY2030 and 349 kT in FY2031. Other scenarios show minimal divergence, all clustering within a narrow band of 348–352 kT. This indicates that dispatch strategies and optimization levers have limited impact on Matimba's SO_2 profile. Matla's SO_2 emissions start at approximately 180 kT in FY2027 and decline steadily to around 130–138 kT by FY2031, reflecting a meaningful reduction of about 23% for five scenarios. However, for the *Additional* cost scenario, SO_2 emissions are 143 kT in FY2027 and gradually declines to 94 kT by FY2031. Medupi's SO_2 emissions remain stable over the projection period, starting at about 254 kT in FY2027 and gradually declining to approximately 235 kT by FY2031.This represents a modest reduction of around 7 - 8%, indicating that current dispatch strategies and operational constraints have only a limited impact on lowering emissions at this station. The data suggests that dispatch optimization alone cannot deliver substantial improvements for Medupi, and meaningful reductions will require structural interventions such as flue gas desulphurization (FGD) or other advanced abatement technologies. These measures will be critical to achieving compliance and reducing environmental impact beyond incremental gains from operational adjustments. Tutuka's SO_2 emissions show a downward trend from around 65 kT to 42kT for FY2027 to FY2030. However, there is a slight increase in FY2031, but overall when comparing the FY2027 and FY2031, there is an overall decrease.

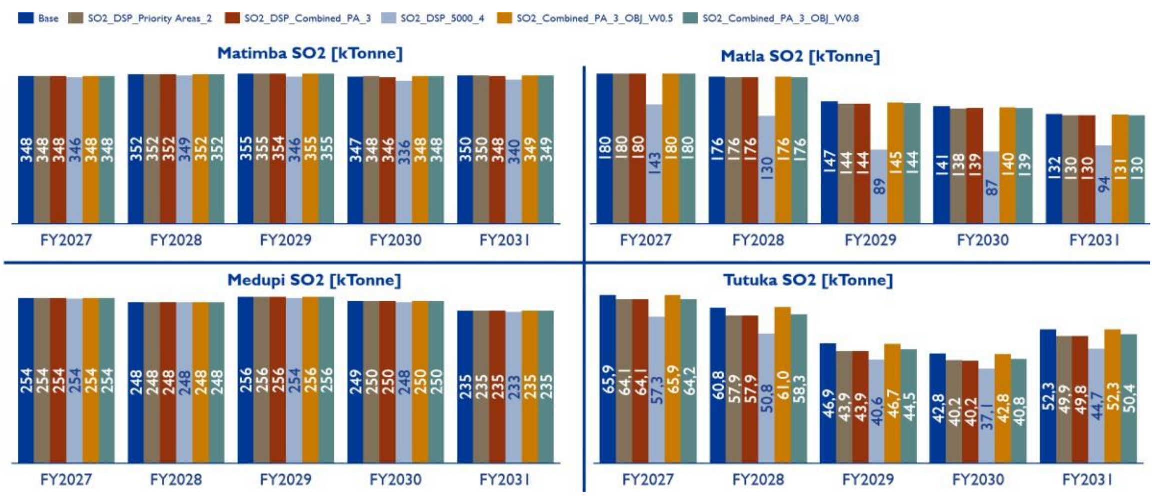

Figure 42: SO_2 emissions for Matima, Matla, Medupi, and Tutuka power stations.